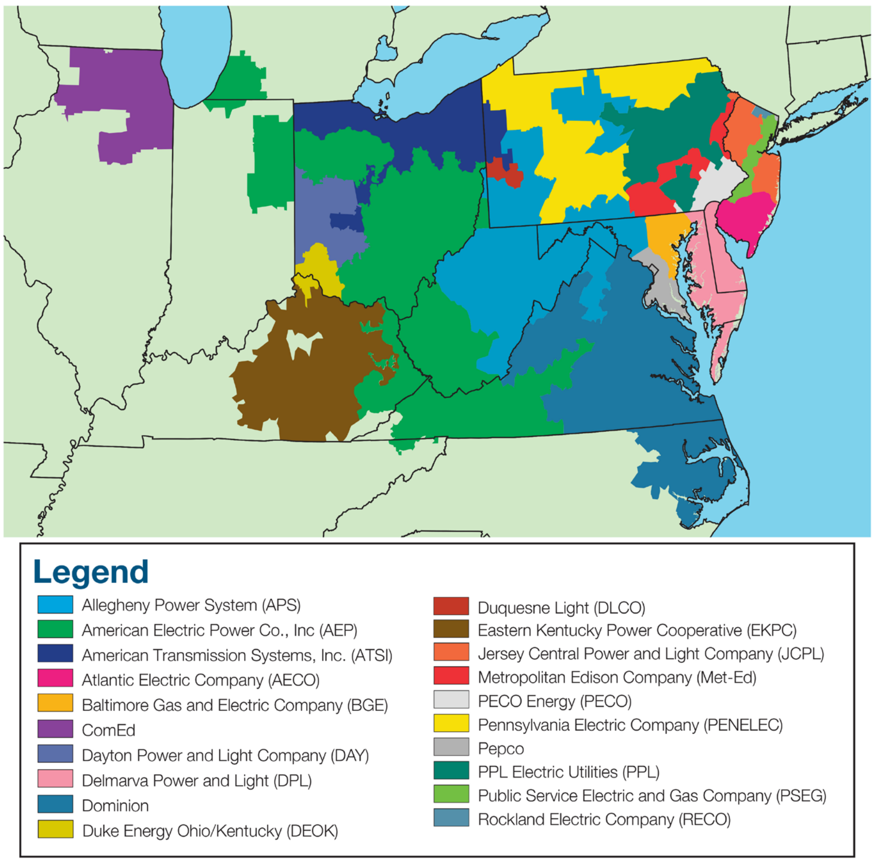
Appendix A PJM Geography

In 2017, the PJM footprint included 20 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure A-1).

Figure A-1 PJM's footprint and its 20 control zones

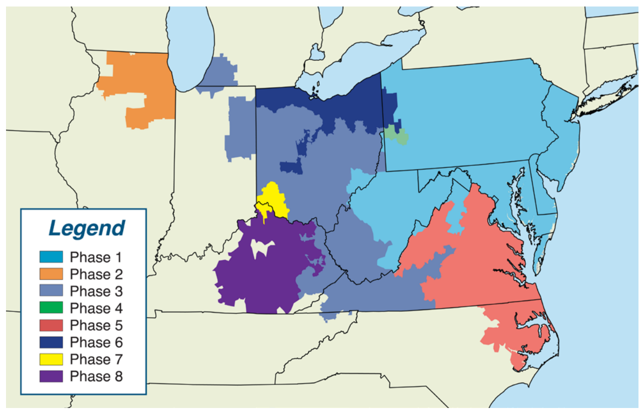


Analysis of 2017 market results includes comparisons to market results in prior years. In 2016, 2015 and 2014 no changes were made to the PJM footprint. In 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC) Control Zone. In 2012, PJM integrated the Duke Energy Ohio and Kentucky (DEOK) Control Zone. In 2011, PJM integrated the ATSI Control Zone. In 2006 through 2010, the PJM footprint was stable. In 2004 and 2005, PJM integrated five new control zones, three in 2004 and two in 2005.

Figure A-2 shows the eight phases corresponding to market integration dates:[1]

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, and the Allegheny Power System (APS) Control Zone.[2 3]
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the APS Control Zone and the ComEd Control Area.[4]
- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the APS Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.
- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the APS Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.
- **Phase 5 (2005 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011, during which PJM was comprised of the Phase 5 elements plus the ATSI Control Zone which was integrated into PJM on June 1, 2011.
- **Phase 7 (2012).** The period from January 1, 2012, through May 31, 2013, during which PJM was comprised of the Phase 6 elements plus the DEOK Control Zone which was integrated into PJM on January 1, 2012.
- **Phase 8 (2013 through the present).** The period from June 1, 2013, through the present, during which PJM was comprised of the Phase 7 elements plus the EKPC Control Zone which was integrated into PJM on June 1, 2013.

Figure A-2 PJM integration phases



A locational deliverability area (LDA), defined in the RPM Capacity Market, is a Control Zone, part of a Control Zone, or a combination of Control Zones within PJM with defined internal generation and defined transmission capability to import capacity.[5]

Figure A-3 shows LDAs that are combinations of Control Zones. Figure A-4 and Figure A-5 show LDAs that are part of a Control Zone.

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

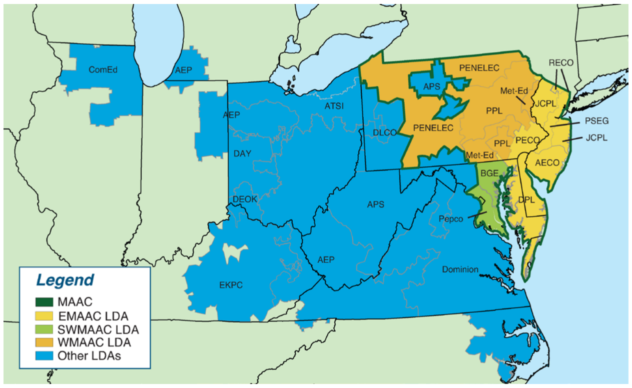
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones. The AP Control Zone was integrated in 2002. The RECO Control Zone was integrated in 2002.

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

5 OATT Attachment DD § 2.38.

Figure A-3 PJM locational deliverability areas



In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal capacity without the purchase of out of merit capacity internal capacity. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price, and the Rest of RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North. For the 2015/2016 Base Residual Auction, the defined markets were RTO, MAAC, and ATSI. For the 2016/2017 Base Residual Auction, the defined markets were RTO, MAAC, PSEG, and ATSI. For the 2017/2018 Base Residual Auction, the defined markets were RTO and PSEG. For the 2018/2019 Base Residual Auction, the defined markets were RTO, EMAAC, and ComEd. For the 2019/2020 Base Residual Auction, the defined markets were RTO, EMAAC, ComEd, and BGE. For the 2020/2021 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, ComEd, and DEOK.

Figure A-4 PJM RPM EMAAC locational deliverability area, including PSEG North and DPL South

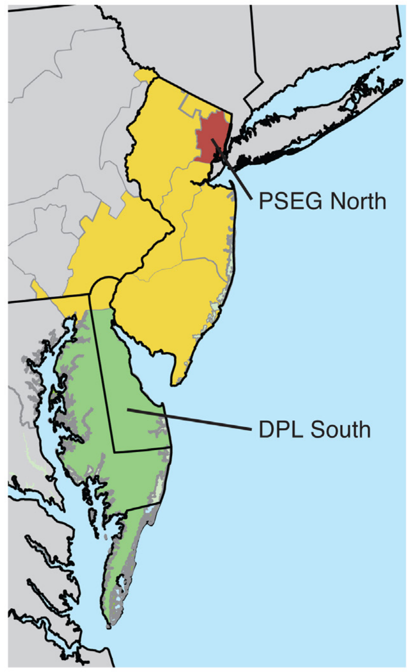
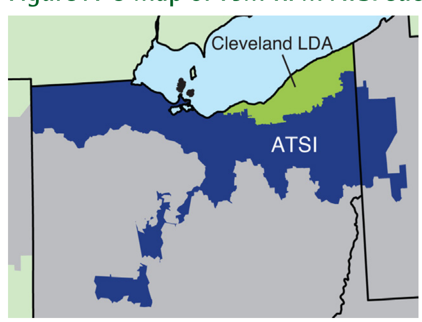


Figure A-5 Map of PJM RPM ATSI subzonal LDA



Appendix B PJM Market Milestones

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
	June	Auction Revenue Rights (ARRs)
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day-Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve accounting rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM
2012	January	Integration of DEOK Control Zone into PJM
	October	Regulation Market: Slow and fast frequency response
	October	Scarcity pricing in Energy Market
2013	June	Integration of Eastern Kentucky Power Cooperative (EKPC) into PJM
2015	August	First Capacity Performance Auction

Appendix C Energy Market

This appendix provides more detailed information about load, locational marginal prices (LMP), offer-capped units and energy market uplift (operating reserves).

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for 2007 through 2017.[1] The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the load was between zero GWh and 20 GWh and then by five GWh intervals. The integrations of the APS Control Zone in 2002, the ComEd, AEP and DAY control zones in 2004, the DLCO and Dominion control zones in 2005, the ATSI Control Zone in 2011, the DEOK Control Zone in 2012, and the EKPC Control Zone in 2013 mean that annual comparisons of load frequency are significantly affected by PJM's growth.[2]

Table C-1 Frequency distribution of PJM real-time, hourly load: 2007 through 2017[3]

	2007		2008		2009		2010		2011		2012	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%	0	0.00%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%	0	0.00%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%	104	1.18%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%	471	6.55%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	858	21.62%	629	13.71%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.41%	785	22.64%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,176	47.83%	1,010	34.14%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,259	62.20%	1,390	49.97%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%	1,233	64.00%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	719	82.10%	973	75.08%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	495	87.75%	691	82.95%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%	436	87.91%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%	289	91.20%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%	185	93.31%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%	152	95.04%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%	135	96.57%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%	121	97.95%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%	77	98.83%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%	46	99.35%
140 to 145	0	100.00%	0	100.00%	0	100.00%	0	100.00%	16	99.83%	39	99.80%
145 to 150	0	100.00%	0	100.00%	0	100.00%	0	100.00%	9	99.93%	16	99.98%
150 to 155	0	100.00%	0	100.00%	0	100.00%	0	100.00%	6	100.00%	2	100.00%
155 to 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

1 The definitions of load are discussed in the *Technical Reference for PJM Markets*, at "Load Definitions." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

2 See the *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

3 Each range in the tables in this Appendix excludes the start value and includes the end value.

Table C-1 Frequency distribution of PJM real-time, hourly load: 2007 through 2017 (continued)

	2013		2014		2015		2016		2017	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
50 to 55	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
55 to 60	81	0.92%	78	0.89%	76	0.87%	74	0.84%	87	0.99%
60 to 65	390	5.38%	379	5.22%	447	5.97%	443	5.89%	463	6.28%
65 to 70	572	11.91%	573	11.76%	636	13.23%	601	12.73%	606	13.20%
70 to 75	728	20.22%	726	20.05%	793	22.28%	811	21.96%	840	22.79%
75 to 80	857	30.00%	800	29.18%	867	32.18%	905	32.26%	1,005	34.26%
80 to 85	1,177	43.44%	1,170	42.53%	1,289	46.89%	1,500	49.34%	1,417	50.43%
85 to 90	1,224	57.41%	1,241	56.70%	1,083	59.26%	1,049	61.28%	1,211	64.26%
90 to 95	1,042	69.30%	860	66.52%	803	68.42%	722	69.50%	955	75.16%
95 to 100	877	79.32%	785	75.48%	625	75.56%	642	76.81%	641	82.48%
100 to 105	682	87.10%	685	83.30%	558	81.93%	520	82.73%	449	87.60%
105 to 110	401	91.68%	550	89.58%	515	87.81%	395	87.23%	333	91.40%
110 to 115	270	94.76%	357	93.65%	384	92.19%	367	91.40%	294	94.76%
115 to 120	157	96.55%	225	96.22%	286	95.46%	231	94.03%	196	97.00%
120 to 125	127	98.00%	156	98.00%	162	97.31%	152	95.77%	117	98.33%
125 to 130	67	98.77%	100	99.14%	128	98.77%	160	97.59%	82	99.27%
130 to 135	42	99.25%	63	99.86%	72	99.59%	111	98.85%	36	99.68%
135 to 140	20	99.47%	12	100.00%	34	99.98%	75	99.70%	19	99.90%
140 to 145	14	99.63%	0	100.00%	2	100.00%	17	99.90%	9	100.00%
145 to 150	20	99.86%	0	100.00%	0	100.00%	9	100.00%	0	100.00%
150 to 155	12	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
155 to 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> 160	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Off Peak and On Peak Load

Table C-2 shows summary load statistics for 1998 through 2017 for the off peak and on peak hours. Table C-3 shows the annual change in each statistic. The on peak period is defined for each weekday (Monday through Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays.

Table C-2 Off peak and on peak load (MW): 1998 through 2017

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,765	84,375	1.23	67,198	81,842	1.22	10,916	10,519	0.96
2010	72,222	88,087	1.22	70,354	85,504	1.22	12,935	13,775	1.06
2011	74,815	91,413	1.22	72,661	87,938	1.21	12,978	14,835	1.14
2012	79,046	96,193	1.22	76,930	92,199	1.20	13,182	14,426	1.09
2013	80,232	97,624	1.22	78,751	95,465	1.21	12,588	13,105	1.04
2014	80,942	98,456	1.22	78,993	97,042	1.23	13,086	13,161	1.01
2015	80,669	97,620	1 .21	77,648	94,316	1.21	14,288	14,387	1.01
2016	80,676	97,737	1.21	78,001	94,087	1.21	14,227	15,806	1.11
2017	79,237	95,147	1.20	77,160	91,910	1.19	12,664	13,230	1.04

Table C-3 Changes in off peak and on peak load (MW): 1998 through 2017

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.7%)	(4.0%)	0.7%	(4.7%)	(4.2%)	0.5%	(4.1%)	(6.1%)	(2.1%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.5%	(0.2%)	18.5%	30.9%	10.5%
2011	3.6%	3.8%	0.2%	3.3%	2.8%	(0.4%)	0.3%	7.7%	7.3%
2012	5.7%	5.2%	(0.4%)	5.9%	4.8%	(1.0%)	1.6%	(2.8%)	(4.3%)
2013	1.5%	1.5%	(0.0%)	2.4%	3.5%	1.1%	(4.5%)	(9.2%)	(4.9%)
2014	0.9%	0.9%	(0.0%)	0.3%	1.7%	1.3%	4.0%	0.4%	(3.4%)
2015	(0.3%)	(0.8%)	(0.5%)	(1.7%)	(2.8%)	(1.1%)	9.2%	9.3%	0.1%
2016	0.0%	0.1%	0.1%	0.5%	(0.2%)	(0.7%)	(0.4%)	9.9%	10.3%
2017	(1.8%)	(2.6%)	(0.9%)	(1.1%)	(2.3%)	(1.2%)	(11.0%)	(16.3%)	(6.0%)

Locational Marginal Price (LMP)

Three measures of LMP are calculated: average LMP; load-weighted average LMP; and fuel-cost adjusted, load-weighted average LMP. Differences in average LMP measure the change in reported price. Differences in load-weighted average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost adjusted, load-weighted average LMP measure what the change in reported price actually paid by load would have been if fuel costs in 2017 had been the same as in 2016, holding everything else constant.[4]

The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly contribution to total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

During the settlement process, total load that is assigned to a load serving entity (LSE) in a zone is settled based on the LSE's choice to be charged either at the zonal price or at a different defined aggregate of nodal prices. Any LSE may request to settle at a different aggregate price instead of zonal LMP, but the change can only take effect on June 1 of each year.[5] If an LSE chooses to settle at a different aggregate, the load of the LSE is distributed to all of the buses in the aggregate.[6] If the LSE settles at the zonal price, the load of the LSE will be distributed to all of the buses in the zone.[7]

Market rules related to the use of zonal pricing will change starting with the 2015/2016 planning period.[8] A residual zonal price will become the default price for load that has not elected to settle at nodal prices. When some load in a zone is nodally priced, the residual zonal price is the price of energy for the residual load, the load that is not priced nodally. The residual price is the average price at the nodes at which non-nodal load is served. The zonal LMP will continue to be used for virtual bidding, Financial Transmission Rights (FTRs), and bilateral energy transactions.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[9]

4 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price."

5 See PJM "Manual 27: Open Access Transmission Tariff Accounting," Rev. 89 (April 1, 2018), Section 5, p. 22-24.

6 OATT. Common Service Provisions (Designation of Network Load) §31.7.

7 *Id*

8 *Id.*

9 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Rev. 97 (July 26, 2018), Section 2, p. 18.

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table C-4 provides frequency distributions of PJM real-time hourly average LMP for 2007 through 2016. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time LMP was, when negative, within a $100 per MWh price interval below $0 per MWh, or, when positive, within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh. In the Real-Time Energy Market, prices reached a high for the year of $227.87 per MWh on December 9, 2016, in the hour ending 0800 EPT.

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 through 2017

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
-$200 to -$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.02%
-$100 to $0	23	0.26%	45	0.51%	60	0.68%	34	0.39%	33	0.38%	50	0.59%
$0 to $10	33	0.64%	49	1.07%	57	1.34%	31	0.74%	33	0.75%	79	1.49%
$10 to $20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%	510	7.30%
$20 to $30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%	4,002	52.86%
$30 to $40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%	2,801	84.74%
$40 to $50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%	668	92.35%
$50 to $60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%	244	95.13%
$60 to $70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%	136	96.68%
$70 to $80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%	75	97.53%
$80 to $90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%	51	98.11%
$90 to $100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%	38	98.54%
$100 to $110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%	32	98.91%
$110 to $120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%	20	99.13%
$120 to $130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%	15	99.31%
$130 to $140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%	10	99.42%
$140 to $150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%	7	99.50%
$150 to $160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%	8	99.59%
$160 to $170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%	5	99.65%
$170 to $180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%	1	99.66%
$180 to $190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%	2	99.68%
$190 to $200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%	3	99.72%
$200 to $210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%	2	99.74%
$210 to $220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%	1	99.75%
$220 to $230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%	0	99.75%
$230 to $240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%	4	99.80%
$240 to $250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%	5	99.85%
$250 to $260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%	5	99.91%
$260 to $270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%	0	99.91%
$270 to $280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%	1	99.92%
$280 to $290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%	1	99.93%
$290 to $300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%	0	99.93%
$300 to $400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%	6	100.00%
$400 to $500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$600 to $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$700 to $800	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%
$800 to $900	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 through 2017 (continued)

	2013		2014		2015		2016		2017	
		Cumulative		Cumulative		Cumulative		Cumulative		Cumulative
LMP	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent
-$200 to -$100	0	0.00%	0	0.00%	5	0.06%	0	0.00%	0	0.00%
-$100 to $0	3	0.03%	15	0.17%	31	0.41%	18	0.20%	19	0.22%
$0 to $10	64	0.76%	40	0.63%	108	1.64%	67	0.97%	28	0.54%
$10 to $20	147	2.44%	224	3.18%	1,091	14.10%	1,690	20.21%	1,143	13.58%
$20 to $30	3,077	37.57%	2,662	33.57%	4,527	65.78%	4,931	76.34%	4,959	70.19%
$30 to $40	3,447	76.92%	2,782	65.33%	1,477	82.64%	1,217	90.20%	1,605	88.52%
$40 to $50	1,116	89.66%	1,161	78.58%	566	89.10%	382	94.55%	451	93.66%
$50 to $60	391	94.12%	619	85.65%	270	92.18%	156	96.32%	225	96.23%
$60 to $70	187	96.26%	287	88.93%	168	94.10%	116	97.64%	108	97.47%
$70 to $80	99	97.39%	206	91.28%	116	95.42%	79	98.54%	68	98.24%
$80 to $90	67	98.15%	142	92.90%	89	96.44%	49	99.10%	47	98.78%
$90 to $100	38	98.58%	102	94.06%	77	97.32%	17	99.29%	33	99.16%
$100 to $110	23	98.85%	71	94.87%	42	97.80%	22	99.54%	21	99.39%
$110 to $120	24	99.12%	55	95.50%	31	98.15%	11	99.67%	15	99.57%
$120 to $130	13	99.27%	50	96.07%	29	98.48%	7	99.75%	10	99.68%
$130 to $140	20	99.50%	42	96.55%	24	98.76%	4	99.80%	6	99.75%
$140 to $150	1	99.51%	21	96.79%	11	98.88%	4	99.84%	4	99.79%
$150 to $160	3	99.54%	22	97.04%	21	99.12%	3	99.87%	6	99.86%
$160 to $170	4	99.59%	22	97.29%	9	99.22%	2	99.90%	1	99.87%
$170 to $180	5	99.65%	21	97.53%	12	99.36%	5	99.95%	3	99.91%
$180 to $190	3	99.68%	24	97.81%	6	99.43%	0	99.95%	2	99.93%
$190 to $200	1	99.69%	18	98.01%	6	99.50%	3	99.99%	0	99.93%
$200 to $210	3	99.73%	17	98.21%	8	99.59%	0	99.99%	1	99.94%
$210 to $220	4	99.77%	14	98.37%	5	99.65%	0	99.99%	0	99.94%
$220 to $230	3	99.81%	11	98.49%	4	99.69%	1	100.00%	2	99.97%
$230 to $240	4	99.85%	10	98.61%	4	99.74%	0	100.00%	0	99.97%
$240 to $250	1	99.86%	8	98.70%	3	99.77%	0	100.00%	0	99.97%
$250 to $260	1	99.87%	6	98.77%	4	99.82%	0	100.00%	0	99.97%
$260 to $270	3	99.91%	5	98.82%	2	99.84%	0	100.00%	0	99.97%
$270 to $280	1	99.92%	9	98.93%	1	99.85%	0	100.00%	1	99.98%
$280 to $290	0	99.92%	10	99.04%	2	99.87%	0	100.00%	0	99.98%
$290 to $300	1	99.93%	7	99.12%	1	99.89%	0	100.00%	0	99.98%
$300 to $400	5	99.99%	35	99.52%	7	99.97%	0	100.00%	0	99.98%
$400 to $500	1	100.00%	22	99.77%	3	100.00%	0	100.00%	1	99.99%
$500 to $600	0	100.00%	6	99.84%	0	100.00%	0	100.00%	0	99.99%
$600 to $700	0	100.00%	1	99.85%	0	100.00%	0	100.00%	1	100.00%
$700 to $800	0	100.00%	2	99.87%	0	100.00%	0	100.00%	0	100.00%
$800 to $900	0	100.00%	4	99.92%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	0	100.00%	1	99.93%	0	100.00%	0	100.00%	0	100.00%
> $1,000	0	100.00%	6	100.00%	0	100.00%	0	100.00%	0	100.00%

Off Peak and On Peak, PJM Real-Time, Load-Weighted Average LMP

Table C-5 shows load-weighted, average real-time LMP for 2016 and 2017 during off peak and on peak periods.

Table C-5 Off peak and on peak, PJM load-weighted, average LMP (Dollars per MWh): 2016 and 2017

	2016			2017			Percent Change		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$24.20	$34.02	1.41	$26.61	$35.20	1.32	10.0%	3.5%	(5.9%)
Median	$22.08	$28.03	1.27	$23.01	$29.83	1.30	4.2%	6.4%	2.1%
Standard deviation	$11.37	$18.35	1.61	$14.76	$22.07	1.50	29.8%	20.2%	(7.4%)

Off Peak and On Peak, Real-Time, Fuel-Cost Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. The supply curve is a function of the short run marginal costs of marginal units, the units setting LMP. As competitive offers are the short run marginal costs of generation and fuel costs make up between 80 percent and 90 percent of short run marginal costs on average, fuel cost is a key factor affecting the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[10] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2016 and 2017, the load-weighted, average LMP for 2017 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2016. The fuel cost adjusted, load-weighted, average LMP for 2017 is compared to the load-weighted, average LMP for 2016 and load-weighted, average LMP for 2017.[11]

Table C-6 shows the real-time, load-weighted, average LMP for 2017 and the real-time, fuel-cost adjusted, load-weighted, average LMP for 2017 for on-peak and off-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2017 on-peak hours was 20.6 percent lower than the load-weighted, average LMP for 2017 on-peak hours. If the fuel costs had been the same as in 2016, holding everything else constant, the 2017 real time load-weighted, average LMP for on-peak hours would have been lower, $27.95 per MWh than the observed $35.20 per MWh. The fuel-cost adjusted load-weighted, average LMP for 2017 off-peak hours was 14.6 percent lower than the load-weighted, average LMP for 2017 off-peak hours. If the fuel costs had been the same as in 2016, holding everything else constant, the 2017 real-time load-weighted, average LMP for off-peak hours would have been lower, $22.74 per MWh instead of the observed $26.61 per MWh. The increase in fuel and emissions costs in 2017 resulted in higher prices in 2017 for on peak and off peak periods than would have occurred if fuel and emissions costs had remained at their 2016 levels. The increase in fuel costs accounted for 17.9 percent of the increase in load-weighted LMP from 2016 to 2017 for the peak period and 6.0 percent for the off-peak period.

Table C-6 On peak and off peak real-time PJM fuel-cost adjusted, load-weighted, average LMP (Dollars per MWh): year over year

	2017 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Off Peak Average	$26.61	$22.74	(14.6%)
Peak Average	$35.20	$27.95	(20.6%)
	2016 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Off Peak Average	$24.20	$22.74	(6.0%)
Peak Average	$34.02	$27.95	(17.9%)
	2016 Load-Weighted LMP	2017 Load-Weighted LMP	Change
Off Peak Average	$24.20	$26.61	10.0%
Peak Average	$34.02	$35.20	3.5%

PJM Real-Time, Load-Weighted Average LMP during Constrained Hours

Table C-7 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2016 and 2017.

Table C-7 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): 2016 and 2017

	2016		2017		Percent Change	
	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours	Constrained Hours
Average	$21.55	$29.75	$24.42	$31.81	13.3%	7.0%
Median	$21.41	$25.27	$23.15	$26.99	8.1%	6.8%
Standard deviation	$7.55	$16.41	$7.06	$20.20	(6.4%)	23.1%

10 See the *2017 State of the Market Report for PJM*, Volume II, Section 3,"Energy Market," at Table 3-7, "Type of fuel used (By real-time marginal units): 2013 through 2017."

11 See the *Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table C-8 shows the number of hours and the number of constrained hours in each month in 2016 and 2017.

Table C-8 PJM real-time constrained hours: 2016 and 2017

	2016			2017		
	Constrained Hours	Total Hours	Percent of Total	Constrained Hours	Total Hours	Percent of Total
Jan	661	744	88.8%	660	744	88.7%
Feb	666	696	95.7%	632	672	94.0%
Mar	734	743	98.8%	707	743	95.2%
Apr	694	720	96.4%	595	720	82.6%
May	638	744	85.8%	650	744	87.4%
Jun	621	720	86.3%	648	720	90.0%
Jul	692	744	93.0%	610	744	82.0%
Aug	702	744	94.4%	607	744	81.6%
Sep	704	720	97.8%	706	720	98.1%
Oct	742	744	99.7%	739	744	99.3%
Nov	650	721	90.2%	618	721	85.7%
Dec	666	744	89.5%	560	744	75.3%
Avg	681	732	93.0%	644	730	88.3%

Day-Ahead LMP

Frequency Distribution of Day-Ahead Average LMP

Table C-9 provides frequency distributions of PJM day-ahead hourly average LMP for 2007 through 2017. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM day-ahead LMP was, when negative, within a $100 per MWh price interval below $0 per MWh, or, when positive, within a $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh.

In the Day-Ahead Energy Market, prices reached a high for the year of $224.59 per MWh on September 25, 2017, in the hour ending 1700 EPT.

Table C-9 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): 2007 through 2017

	2007		2008		2009		2010		2011		2012	
		Cumulative		Cumulative		Cumulative		Cumulative		Cumulative		Cumulative
LMP	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent
-$200 to -$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-$100 to $0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
$0 to $10	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%	19	0.22%
$10 to $20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%	467	5.53%
$20 to $30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%	3,402	44.26%
$30 to $40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%	3,521	84.35%
$40 to $50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%	908	94.68%
$50 to $60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%	247	97.50%
$60 to $70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%	106	98.70%
$70 to $80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%	39	99.15%
$80 to $90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%	21	99.39%
$90 to $100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%	12	99.52%
$100 to $110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%	7	99.60%
$110 to $120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%	6	99.67%
$120 to $130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%	7	99.75%
$130 to $140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%	4	99.80%
$140 to $150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%	2	99.82%
$150 to $160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%	1	99.83%
$160 to $170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%	3	99.86%
$170 to $180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%	1	99.87%
$180 to $190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%	0	99.87%
$190 to $200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%	2	99.90%
$200 to $210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%	2	99.92%
$210 to $220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%	2	99.94%
$220 to $230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%	1	99.95%
$230 to $240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%	2	99.98%
$240 to $250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%	0	99.98%
$250 to $260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%	1	99.99%
$260 to $270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%	0	99.99%
$270 to $280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%	1	100.00%
$280 to $290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%	0	100.00%
$290 to $300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%	0	100.00%
$300 to $400	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%	0	100.00%
$400 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$500 to $600	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$600 to $700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$700 to $800	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$800 to $900	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2013		2014		2015		2016		2017	
		Cumulative		Cumulative		Cumulative		Cumulative		Cumulative
LMP	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent	Frequency	Percent
-$200 to -$100	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
-$100 to $0	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
$0 to $10	1	0.01%	12	0.14%	71	0.81%	35	0.40%	5	0.06%
$10 to $20	76	0.88%	112	1.42%	871	10.75%	1,462	17.04%	1,056	12.11%
$20 to $30	2,364	27.87%	2,106	25.46%	3,760	53.68%	4,509	68.37%	4,356	61.84%
$30 to $40	3,794	71.18%	2,648	55.68%	2,430	81.42%	1,837	89.29%	2,342	88.57%
$40 to $50	1,761	91.28%	1,866	76.99%	772	90.23%	592	96.03%	651	96.00%
$50 to $60	421	96.08%	827	86.43%	293	93.57%	204	98.35%	173	97.98%
$60 to $70	169	98.01%	346	90.38%	130	95.06%	73	99.18%	70	98.78%
$70 to $80	64	98.74%	191	92.56%	97	96.16%	34	99.57%	35	99.18%
$80 to $90	35	99.14%	108	93.79%	83	97.11%	21	99.81%	26	99.47%
$90 to $100	22	99.39%	77	94.67%	64	97.84%	7	99.89%	16	99.66%
$100 to $110	12	99.53%	51	95.25%	37	98.26%	6	99.95%	9	99.76%
$110 to $120	4	99.58%	33	95.63%	34	98.65%	4	100.00%	8	99.85%
$120 to $130	3	99.61%	26	95.92%	34	99.04%	0	100.00%	7	99.93%
$130 to $140	2	99.63%	34	96.31%	17	99.24%	0	100.00%	2	99.95%
$140 to $150	2	99.66%	18	96.52%	11	99.36%	0	100.00%	0	99.95%
$150 to $160	2	99.68%	31	96.87%	10	99.47%	0	100.00%	1	99.97%
$160 to $170	5	99.74%	22	97.12%	10	99.59%	0	100.00%	0	99.97%
$170 to $180	3	99.77%	26	97.42%	8	99.68%	0	100.00%	0	99.97%
$180 to $190	2	99.79%	29	97.75%	2	99.70%	0	100.00%	1	99.98%
$190 to $200	2	99.82%	24	98.03%	4	99.75%	0	100.00%	1	99.99%
$200 to $210	3	99.85%	14	98.18%	1	99.76%	0	100.00%	0	99.99%
$210 to $220	2	99.87%	13	98.33%	3	99.79%	0	100.00%	0	99.99%
$220 to $230	4	99.92%	15	98.50%	1	99.81%	0	100.00%	1	100.00%
$230 to $240	0	99.92%	8	98.60%	1	99.82%	0	100.00%	0	100.00%
$240 to $250	1	99.93%	10	98.71%	2	99.84%	0	100.00%	0	100.00%
$250 to $260	1	99.94%	6	98.78%	2	99.86%	0	100.00%	0	100.00%
$260 to $270	0	99.94%	9	98.88%	4	99.91%	0	100.00%	0	100.00%
$270 to $280	1	99.95%	15	99.05%	3	99.94%	0	100.00%	0	100.00%
$280 to $290	0	99.95%	7	99.13%	0	99.94%	0	100.00%	0	100.00%
$290 to $300	2	99.98%	6	99.20%	1	99.95%	0	100.00%	0	100.00%
$300 to $400	2	100.00%	31	99.55%	4	100.00%	0	100.00%	0	100.00%
$400 to $500	0	100.00%	15	99.73%	0	100.00%	0	100.00%	0	100.00%
$500 to $600	0	100.00%	12	99.86%	0	100.00%	0	100.00%	0	100.00%
$600 to $700	0	100.00%	6	99.93%	0	100.00%	0	100.00%	0	100.00%
$700 to $800	0	100.00%	1	99.94%	0	100.00%	0	100.00%	0	100.00%
$800 to $900	0	100.00%	1	99.95%	0	100.00%	0	100.00%	0	100.00%
$900 to $1000	0	100.00%	4	100.00%	0	100.00%	0	100.00%	0	100.00%
> $1000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Off Peak and On Peak, Day-Ahead and Real-Time, Average LMP

Table C-10 shows PJM average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in 2017. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in 2017 during the on-peak and off-peak hours.

Table C-10 Off peak and on peak, average day-ahead and real-time LMP (Dollars per MWh): 2017

	Day Ahead		Real Time		Difference		Percent Change	
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak
Average	$25.20	$34.42	$25.39	$34.07	($0.20)	$0.35	0.8%	(1.0%)
Median	$22.98	$31.97	$22.57	$29.34	$0.41	$2.63	(1.8%)	(8.2%)
Standard Deviation	$8.95	$12.50	$13.33	$20.17	($4.38)	($7.67)	48.9%	61.4%

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): 2017

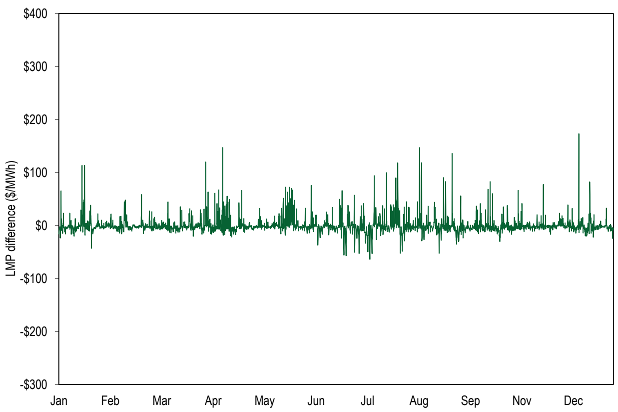
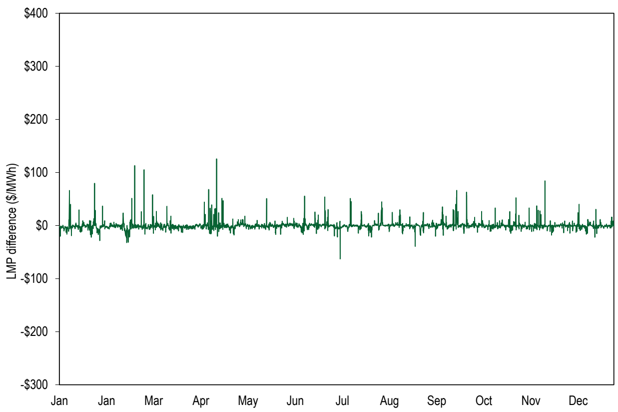


Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): 2017



On Peak and Off Peak, Zonal, Day-Ahead and Real-Time, Average LMP

Table C-11 and Table C-12 show the on peak and off peak, average LMP for each zone in the Day-Ahead and Real-Time Energy Markets in 2016 and 2017.

Table C-11 On peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2016 and 2017

	2016				2017			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	$29.95	$29.01	($0.94)	(3.2%)	$31.91	$31.71	($0.19)	(0.6%)
AEP	$33.29	$32.65	($0.64)	(2.0%)	$34.19	$33.35	($0.84)	(2.5%)
APS	$34.10	$33.27	($0.83)	(2.5%)	$34.72	$34.32	($0.40)	(1.2%)
ATSI	$33.85	$33.61	($0.24)	(0.7%)	$35.25	$34.97	($0.27)	(0.8%)
BGE	$43.89	$43.33	($0.56)	(1.3%)	$37.97	$37.15	($0.82)	(2.2%)
ComEd	$32.07	$31.58	($0.49)	(1.5%)	$32.45	$32.15	($0.31)	(1.0%)
DAY	$33.53	$32.71	($0.82)	(2.5%)	$35.10	$34.30	($0.80)	(2.3%)
DEOK	$32.98	$31.87	($1.12)	(3.5%)	$34.65	$33.78	($0.88)	(2.6%)
DLCO	$32.88	$32.78	($0.09)	(0.3%)	$34.55	$34.12	($0.43)	(1.3%)
Dominion	$36.51	$35.39	($1.12)	(3.2%)	$36.75	$36.03	($0.72)	(2.0%)
DPL	$33.54	$31.73	($1.81)	(5.7%)	$34.58	$34.31	($0.27)	(0.8%)
EKPC	$32.00	$31.19	($0.82)	(2.6%)	$32.99	$31.67	($1.32)	(4.2%)
JCPL	$29.19	$28.49	($0.71)	(2.5%)	$32.84	$32.80	($0.03)	(0.1%)
Met-Ed	$29.89	$29.22	($0.67)	(2.3%)	$34.11	$34.31	$0.19	0.6%
PECO	$28.88	$28.11	($0.77)	(2.7%)	$31.91	$31.96	$0.05	0.2%
PENELEC	$31.96	$31.37	($0.59)	(1.9%)	$33.58	$34.30	$0.72	2.1%
Pepco	$39.14	$37.88	($1.26)	(3.3%)	$37.09	$36.16	($0.93)	(2.6%)
PPL	$29.12	$28.42	($0.70)	(2.5%)	$32.45	$32.53	$0.08	0.2%
PSEG	$29.93	$29.06	($0.87)	(3.0%)	$33.77	$33.93	$0.16	0.5%
RECO	$30.02	$29.61	($0.41)	(1.4%)	$33.88	$33.98	$0.11	0.3%

Table C-12 Off peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2016 and 2017

	2016				2017			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	$20.53	$20.44	($0.09)	(0.4%)	$23.93	$24.44	$0.52	2.1%
AEP	$23.77	$23.62	($0.14)	(0.6%)	$25.30	$25.25	($0.04)	(0.2%)
APS	$24.19	$23.89	($0.30)	(1.2%)	$25.75	$25.91	$0.16	0.6%
ATSI	$23.58	$23.48	($0.10)	(0.4%)	$25.58	$25.51	($0.07)	(0.3%)
BGE	$30.60	$29.77	($0.83)	(2.8%)	$28.25	$28.51	$0.26	0.9%
ComEd	$21.66	$21.25	($0.41)	(1.9%)	$22.17	$22.23	$0.06	0.3%
DAY	$23.81	$23.73	($0.08)	(0.3%)	$25.74	$25.66	($0.08)	(0.3%)
DEOK	$23.27	$23.01	($0.26)	(1.1%)	$25.15	$24.91	($0.24)	(1.0%)
DLCO	$23.06	$22.94	($0.12)	(0.5%)	$25.14	$25.01	($0.13)	(0.5%)
Dominion	$26.37	$25.82	($0.55)	(2.1%)	$27.31	$27.47	$0.16	0.6%
DPL	$23.07	$22.24	($0.83)	(3.7%)	$25.91	$27.50	$1.58	5.8%
EKPC	$22.97	$22.98	$0.01	0.0%	$24.68	$24.61	($0.07)	(0.3%)
JCPL	$20.06	$19.85	($0.21)	(1.0%)	$24.18	$24.58	$0.40	1.6%
Met-Ed	$20.15	$19.72	($0.43)	(2.2%)	$24.25	$24.49	$0.24	1.0%
PECO	$19.79	$19.54	($0.25)	(1.3%)	$23.91	$24.39	$0.48	2.0%
PENELEC	$22.27	$21.86	($0.41)	(1.9%)	$24.77	$24.80	$0.03	0.1%
Pepco	$27.83	$27.20	($0.64)	(2.3%)	$27.68	$27.85	$0.17	0.6%
PPL	$20.01	$19.73	($0.28)	(1.4%)	$23.81	$24.10	$0.28	1.2%
PSEG	$20.47	$20.07	($0.40)	(2.0%)	$24.66	$24.82	$0.17	0.7%
RECO	$20.65	$20.14	($0.51)	(2.5%)	$24.73	$24.92	$0.19	0.8%

PJM Day-Ahead and Real-Time, Average LMP during Constrained Hours

Table C-13 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2017.

Table C-13 PJM day-ahead and real-time, market-constrained hours: 2017

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	660	744
Feb	672	632	672
Mar	743	707	743
Apr	720	595	720
May	744	650	744
Jun	720	648	720
Jul	744	610	744
Aug	744	607	744
Sep	720	706	720
Oct	744	739	744
Nov	721	618	721
Dec	744	560	744
Avg	730	644	730

Table C-14 shows PJM average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-14 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): 2017[12]

	Day Ahead		Real Time		Difference		Percent Change	
	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP	Unconstrained Hours LMP	Constrained Hours LMP
Average	NA	$31.46	$23.77	$30.17	NA	($1.29)	NA	(4.1%)
Median	NA	$28.90	$22.78	$25.96	NA	($2.94)	NA	(10.2%)
Standard deviation	NA	$12.76	$6.67	$18.22	NA	$5.47	NA	42.9%

12 All hours in 2017 were constrained in the Day-Ahead Energy Market.

Price Convergence

Table C-15 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2007 through 2017.

Table C-15 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2017

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	4	0.06%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

	2013		2014		2015		2016		2017	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	2	0.02%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	3	0.06%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	1	0.07%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	6	0.14%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	5	0.19%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	5	0.25%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	6	0.32%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	1	0.01%	14	0.48%	1	0.01%	0	0.00%	0	0.00%
($200) to ($150)	3	0.05%	14	0.64%	4	0.06%	0	0.00%	0	0.00%
($150) to ($100)	5	0.10%	45	1.15%	17	0.25%	0	0.00%	2	0.02%
($100) to ($50)	9	0.21%	91	2.19%	65	0.99%	13	0.15%	9	0.13%
($50) to $0	5,994	68.63%	5,829	68.73%	6,034	69.87%	5,780	65.95%	5,460	62.45%
$0 to $50	2,659	98.98%	2,525	97.56%	2,467	98.04%	2,919	99.18%	3,231	99.34%
$50 to $100	64	99.71%	120	98.93%	126	99.47%	58	99.84%	45	99.85%
$100 to $150	12	99.85%	39	99.37%	34	99.86%	13	99.99%	8	99.94%
$150 to $200	10	99.97%	18	99.58%	7	99.94%	1	100.00%	3	99.98%
$200 to $250	1	99.98%	9	99.68%	3	99.98%	0	100.00%	0	99.98%
$250 to $300	2	100.00%	8	99.77%	1	99.99%	0	100.00%	0	99.98%
$300 to $350	0	100.00%	3	99.81%	1	100.00%	0	100.00%	0	99.98%
$350 to $400	0	100.00%	3	99.84%	0	100.00%	0	100.00%	0	99.98%
$400 to $450	0	100.00%	2	99.86%	0	100.00%	0	100.00%	1	99.99%
$450 to $500	0	100.00%	0	99.86%	0	100.00%	0	100.00%	0	99.99%
$500 to $750	0	100.00%	7	99.94%	0	100.00%	0	100.00%	1	100.00%
$750 to $1,000	0	100.00%	0	99.94%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	1	99.95%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	4	100.00%	0	100.00%	0	100.00%	0	100.00%

LMP by Zone and by Jurisdiction

Jurisdiction Real-Time, Average LMP

Table C-16 Jurisdiction real-time, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
Delaware	$24.98	$29.13	$4.14	16.6%
Illinois	$26.05	$26.83	$0.78	3.0%
Indiana	$27.93	$28.74	$0.82	2.9%
Kentucky	$26.95	$28.20	$1.25	4.6%
Maryland	$33.50	$32.07	($1.43)	(4.3%)
Michigan	$28.69	$29.30	$0.61	2.1%
New Jersey	$24.17	$28.74	$4.58	18.9%
North Carolina	$29.49	$30.85	$1.36	4.6%
Ohio	$27.73	$29.45	$1.72	6.2%
Pennsylvania	$24.99	$28.60	$3.61	14.4%
Tennessee	$26.84	$28.35	$1.51	5.6%
Virginia	$30.18	$31.21	$1.03	3.4%
West Virginia	$27.62	$29.08	$1.46	5.3%
District of Columbia	$32.20	$31.82	($0.38)	(1.2%)

Hub Real-Time, Average LMP

Table C-17 Hub real-time, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
AEP Gen Hub	$26.02	$27.80	$1.78	6.8%
AEP-DAY Hub	$27.12	$28.77	$1.65	6.1%
ATSI Gen Hub	$27.70	$29.14	$1.45	5.2%
Chicago Gen Hub	$24.64	$26.43	$1.79	7.3%
Chicago Hub	$25.91	$27.14	$1.23	4.7%
Dominion Hub	$29.37	$29.96	$0.60	2.0%
Eastern Hub	$27.71	$28.40	$0.70	2.5%
N Illinois Hub	$25.61	$26.77	$1.17	4.5%
New Jersey Hub	$23.99	$27.30	$3.31	13.8%
Ohio Hub	$27.29	$28.90	$1.61	5.9%
West Interface Hub	$28.08	$29.30	$1.22	4.3%
Western Hub	$28.44	$28.78	$0.34	1.2%

Jurisdiction Real-Time, Load-Weighted, Average LMP

Table C-18 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
Delaware	$27.68	$31.45	$3.77	13.6%
Illinois	$27.66	$28.29	$0.63	2.3%
Indiana	$29.05	$29.65	$0.61	2.1%
Kentucky	$28.28	$29.44	$1.17	4.1%
Maryland	$35.89	$34.37	($1.52)	(4.2%)
Michigan	$30.35	$30.50	$0.15	0.5%
New Jersey	$31.04	$32.42	$1.38	4.5%
North Carolina	$26.38	$30.75	$4.37	16.6%
Ohio	$29.20	$30.78	$1.58	5.4%
Pennsylvania	$26.69	$30.31	$3.62	13.6%
Tennessee	$28.08	$29.55	$1.47	5.2%
Virginia	$32.10	$33.20	$1.10	3.4%
West Virginia	$28.85	$30.23	$1.38	4.8%
District of Columbia	$33.88	$33.37	($0.51)	(1.5%)

Zonal Day-Ahead, Average LMP

Table C-19 Zonal day-ahead, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
AECO	$24.42	$27.82	$3.39	13.9%
AEP	$27.82	$29.01	$1.19	4.3%
APS	$28.25	$29.81	$1.56	5.5%
ATSI	$28.19	$29.90	$1.71	6.1%
BGE	$36.07	$32.52	($3.55)	(9.8%)
ComEd	$26.05	$26.83	$0.78	3.0%
DAY	$27.90	$29.67	$1.77	6.3%
DEOK	$27.12	$29.02	$1.90	7.0%
DLCO	$30.27	$31.44	$1.17	3.9%
Dominion	$26.65	$30.66	$4.01	15.0%
DPL	$27.51	$29.24	$1.72	6.3%
EKPC	$26.79	$27.89	$1.09	4.1%
JCPL	$23.86	$28.40	$4.53	19.0%
Met-Ed	$24.13	$29.05	$4.91	20.4%
PECO	$23.52	$27.90	$4.38	18.6%
PENELEC	$26.28	$29.21	$2.93	11.2%
Pepco	$32.16	$31.70	($0.46)	(1.4%)
PPL	$23.77	$28.01	$4.24	17.9%
PSEG	$24.25	$29.05	$4.80	19.8%
RECO	$24.54	$29.13	$4.59	18.7%

Jurisdiction Day-Ahead, Average LMP

Table C-20 Jurisdiction day-ahead, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
Delaware	$26.21	$28.42	$2.22	8.5%
Illinois	$26.49	$26.93	$0.44	1.7%
Indiana	$27.88	$28.44	$0.57	2.0%
Kentucky	$27.54	$28.89	$1.35	4.9%
Maryland	$34.26	$32.25	($2.02)	(5.9%)
Michigan	$28.50	$29.72	$1.22	4.3%
New Jersey	$30.14	$31.10	$0.96	3.2%
North Carolina	$24.73	$28.58	$3.85	15.6%
Ohio	$28.07	$29.76	$1.68	6.0%
Pennsylvania	$25.48	$28.44	$2.96	11.6%
Tennessee	$27.68	$29.02	$1.33	4.8%
Virginia	$31.00	$31.54	$0.54	1.7%
West Virginia	$28.24	$29.46	$1.23	4.3%
District of Columbia	$33.11	$32.17	($0.94)	(2.8%)

Zonal Day-Ahead, Load-Weighted, Average LMP

Table C-21 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
AECO	$27.48	$29.14	$1.66	6.0%
AEP	$29.46	$30.56	$1.09	3.7%
APS	$30.18	$31.17	$0.99	3.3%
ATSI	$29.77	$31.23	$1.46	4.9%
BGE	$39.59	$34.78	($4.82)	(12.2%)
ComEd	$28.00	$28.24	$0.25	0.9%
DAY	$29.67	$31.37	$1.70	5.7%
DEOK	$29.30	$31.00	$1.70	5.8%
DLCO	$33.02	$33.59	$0.58	1.8%
Dominion	$31.00	$32.18	$1.18	3.8%
DPL	$29.12	$30.76	$1.65	5.7%
EKPC	$28.62	$29.95	$1.33	4.7%
JCPL	$26.52	$29.92	$3.40	12.8%
Met-Ed	$26.22	$30.44	$4.21	16.1%
PECO	$25.90	$28.97	$3.06	11.8%
PENELEC	$27.86	$29.98	$2.12	7.6%
Pepco	$34.95	$33.71	($1.24)	(3.5%)
PPL	$25.68	$29.30	$3.63	14.1%
PSEG	$26.83	$30.47	$3.64	13.6%
RECO	$27.28	$30.66	$3.38	12.4%

Jurisdiction Day-Ahead, Load-Weighted, Average LMP

Table C-22 Jurisdiction day-ahead, load-weighted, average LMP (Dollars per MWh): 2016 and 2017

	2016	2017	Difference	Percent Change
Delaware	$29.05	$30.47	$1.42	4.9%
Illinois	$27.98	$28.23	$0.25	0.9%
Indiana	$28.98	$29.14	$0.16	0.6%
Kentucky	$28.94	$30.26	$1.32	4.6%
Maryland	$36.65	$34.15	($2.50)	(6.8%)
Michigan	$29.79	$30.74	$0.95	3.2%
New Jersey	$32.01	$32.88	$0.87	2.7%
North Carolina	$26.84	$30.20	$3.36	12.5%
Ohio	$29.45	$30.97	$1.52	5.2%
Pennsylvania	$26.96	$29.77	$2.82	10.4%
Tennessee	$28.82	$30.19	$1.36	4.7%
Virginia	$32.90	$33.35	$0.45	1.4%
West Virginia	$29.57	$30.73	$1.16	3.9%
District of Columbia	$34.84	$33.59	($1.24)	(3.6%)

Zonal Price Differences Between Day-Ahead and Real-Time

Table C-23 Zonal day-ahead and real-time average LMP (Dollars per MWh): 2017

	Day Ahead	Real Time	Difference	Percent of Real Time
AECO	$27.63	$27.82	$0.19	0.7%
AEP	$29.42	$29.01	($0.42)	(1.4%)
APS	$29.91	$29.81	($0.10)	(0.3%)
ATSI	$30.06	$29.90	($0.16)	(0.5%)
BGE	$32.76	$32.52	($0.24)	(0.7%)
ComEd	$26.94	$26.83	($0.11)	(0.4%)
DAY	$30.08	$29.67	($0.41)	(1.4%)
DEOK	$29.56	$29.02	($0.54)	(1.8%)
DLCO	$31.69	$31.44	($0.25)	(0.8%)
Dominion	$29.93	$30.66	$0.72	2.4%
DPL	$29.50	$29.24	($0.27)	(0.9%)
EKPC	$28.53	$27.89	($0.65)	(2.3%)
JCPL	$28.20	$28.40	$0.20	0.7%
Met-Ed	$28.83	$29.05	$0.22	0.7%
PECO	$27.62	$27.90	$0.28	1.0%
PENELEC	$28.86	$29.21	$0.35	1.2%
Pepco	$32.04	$31.70	($0.34)	(1.1%)
PPL	$27.82	$28.01	$0.19	0.7%
PSEG	$28.88	$29.05	$0.16	0.6%
RECO	$28.97	$29.13	$0.15	0.5%
PJM	$29.48	$29.42	($0.06)	(0.2%)

Jurisdictional Price Differences Between Day-Ahead and Real-Time

Table C-24 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): 2017

	Day Ahead	Real Time	Difference	Percent of Real Time
Delaware	$28.42	$29.13	$0.70	2.4%
Illinois	$26.93	$26.83	($0.10)	(0.4%)
Indiana	$28.44	$28.74	$0.30	1.1%
Kentucky	$28.89	$28.20	($0.69)	(2.5%)
Maryland	$32.25	$32.07	($0.18)	(0.6%)
Michigan	$29.72	$29.30	($0.42)	(1.4%)
New Jersey	$31.10	$30.85	($0.25)	(0.8%)
North Carolina	$28.58	$28.74	$0.16	0.6%
Ohio	$29.76	$29.45	($0.31)	(1.1%)
Pennsylvania	$28.44	$28.60	$0.16	0.6%
Tennessee	$29.02	$28.35	($0.67)	(2.3%)
Virginia	$31.54	$31.21	($0.32)	(1.0%)
West Virginia	$29.46	$29.08	($0.39)	(1.3%)
District of Columbia	$32.17	$31.82	($0.35)	(1.1%)

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start, reactive service and for units committed manually as part of conservative operations.

PJM rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[13] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

Levels of offer capping have generally been low and stable over the last five years. Table C-25 through Table C-28 show offer capping by month, including the average number of offer capped units, offer capped unit hours as a percentage of unit run hours, average offer capped MW, and offer capped MW as a percentage of load MW in the Day-Ahead and Real-Time Energy Markets. The statistics include units that are capped for failing the TPS test to provide constraint relief as well as units committed on their cost schedule for reliability reasons (reactive support, black start service and conservative operations).

Table C-25 Average day-ahead, offer capped units: 2013 through 2017

	2013		2014		2015		2016		2017	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	12.6	3.3%	6.3	1.3%	2.5	0.6%	0.8	0.2%	0.9	0.2%
Feb	12.4	3.2%	1.6	0.4%	2.3	0.5%	0.8	0.2%	1.6	0.4%
Mar	10.3	2.7%	2.3	0.5%	2.5	0.6%	0.8	0.2%	1.1	0.3%
Apr	8.6	2.4%	1.6	0.4%	4.3	1.1%	0.1	0.0%	0.4	0.1%
May	10.5	2.8%	1.9	0.5%	4.4	1.1%	0.6	0.1%	0.6	0.2%
Jun	14.5	3.4%	3.2	0.7%	5.4	1.2%	0.2	0.0%	0.0	0.0%
Jul	14.2	3.0%	1.3	0.3%	2.7	0.6%	0.2	0.0%	0.0	0.0%
Aug	13.7	3.2%	0.3	0.1%	2.2	0.5%	0.2	0.0%	0.1	0.0%
Sep	17.1	4.4%	0.7	0.2%	0.9	0.2%	1.2	0.3%	0.5	0.1%
Oct	17.4	4.7%	3.1	0.8%	1.0	0.3%	0.4	0.1%	0.6	0.1%
Nov	12.8	3.3%	4.4	1.1%	1.8	0.5%	1.2	0.3%	0.2	0.0%
Dec	9.0	2.1%	2.7	0.6%	0.7	0.2%	0.8	0.2%	0.2	0.1%

Table C-26 Average day-ahead, offer capped MW: 2013 through 2017

	2013		2014		2015		2016		2017	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	1,949	2.0%	905	0.8%	311	0.3%	144	0.1%	502	0.5%
Feb	1,982	2.0%	372	0.4%	355	0.3%	159	0.2%	525	0.6%
Mar	1,363	1.5%	609	0.6%	402	0.4%	91	0.1%	565	0.6%
Apr	1,340	1.6%	168	0.2%	1,164	1.5%	8	0.0%	243	0.3%
May	1,826	2.2%	179	0.2%	1,015	1.2%	25	0.0%	372	0.5%
Jun	2,486	2.6%	565	0.6%	1,587	1.7%	36	0.0%	0	0.0%
Jul	2,632	2.5%	320	0.3%	858	0.8%	25	0.0%	2	0.0%
Aug	2,076	2.1%	64	0.1%	787	0.8%	9	0.0%	33	0.0%
Sep	2,117	2.4%	79	0.1%	110	0.1%	95	0.1%	76	0.1%
Oct	2,108	2.5%	373	0.5%	243	0.3%	56	0.1%	50	0.1%
Nov	1,791	2.0%	454	0.5%	355	0.4%	464	0.6%	66	0.1%
Dec	1,883	1.9%	282	0.3%	49	0.1%	415	0.4%	48	0.1%

13 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table C-27 Average real-time, offer capped units: 2013 through 2017

	2013		2014		2015		2016		2017	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	13.6	2.9%	13.2	2.4%	3.7	0.8%	2.1	0.4%	2.0	0.4%
Feb	13.8	3.0%	4.3	0.8%	4.7	0.9%	1.5	0.3%	1.8	0.4%
Mar	10.8	2.3%	6.4	1.2%	3.9	0.8%	3.2	0.7%	1.6	0.3%
Apr	9.9	2.2%	1.7	0.4%	5.2	1.1%	1.3	0.3%	1.1	0.2%
May	10.9	2.3%	3.0	0.6%	5.5	1.1%	1.3	0.3%	1.7	0.3%
Jun	15.2	3.0%	4.6	0.9%	6.3	1.2%	1.6	0.3%	1.5	0.3%
Jul	15.8	2.8%	2.6	0.5%	3.5	0.6%	4.2	0.7%	2.1	0.4%
Aug	14.6	2.9%	0.8	0.2%	3.1	0.6%	3.3	0.5%	1.5	0.3%
Sep	20.0	4.2%	1.4	0.3%	2.3	0.5%	3.0	0.6%	4.2	0.8%
Oct	18.1	4.0%	3.8	0.9%	1.8	0.4%	2.5	0.5%	3.8	0.8%
Nov	14.0	3.1%	4.9	1.1%	2.5	0.6%	1.6	0.4%	1.8	0.4%
Dec	11.2	2.4%	3.2	0.7%	1.6	0.3%	1.4	0.3%	3.1	0.6%

Table C-28 Average real-time, offer capped MW: 2013 through 2017

	2013		2014		2015		2016		2017	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	1,886	2.0%	1,363	1.3%	351	0.4%	216	0.2%	557	0.6%
Feb	1,902	2.0%	452	0.5%	353	0.3%	145	0.2%	496	0.6%
Mar	1,315	1.5%	824	0.9%	487	0.5%	276	0.3%	624	0.7%
Apr	1,328	1.7%	192	0.2%	1,091	1.4%	90	0.1%	281	0.4%
May	1,614	2.0%	264	0.3%	1,003	1.2%	69	0.1%	433	0.6%
Jun	2,403	2.6%	649	0.7%	1,580	1.7%	197	0.2%	124	0.1%
Jul	2,632	2.6%	372	0.4%	957	1.0%	437	0.4%	204	0.2%
Aug	2,095	2.2%	90	0.1%	708	0.7%	311	0.3%	128	0.1%
Sep	2,309	2.7%	121	0.1%	207	0.2%	196	0.2%	271	0.3%
Oct	2,223	2.8%	431	0.6%	248	0.3%	222	0.3%	212	0.3%
Nov	2,159	2.5%	425	0.5%	368	0.5%	537	0.7%	294	0.4%
Dec	2,376	2.6%	298	0.3%	100	0.1%	454	0.5%	229	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-29 through Table C-33 show the number of generating units that met the specified criteria for total offer capped run hours and percentage of offer capped run hours for the years 2013 through 2017 in the Real-Time Energy Market.

Table C-29 Offer capped unit statistics: 2013

	2013 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	0	0
80% and < 90%	0	0	0	1	1	3
75% and < 80%	0	0	0	0	1	2
70% and < 75%	0	0	1	0	0	3
60% and < 70%	0	0	0	0	0	4
50% and < 60%	0	0	0	0	0	9
25% and < 50%	0	3	3	1	7	44
10% and < 25%	2	0	0	4	3	46

Table C-30 Offer capped unit statistics: 2014

	2014 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	0	0	0	0	0
80% and < 90%	2	0	0	3	0	0
75% and < 80%	1	0	0	0	1	0
70% and < 75%	0	0	0	0	0	0
60% and < 70%	0	0	0	1	7	5
50% and < 60%	0	0	0	0	3	6
25% and < 50%	0	3	1	1	10	45
10% and < 25%	0	1	4	1	8	56

Table C-31 Offer-capped unit statistics: 2015

	2015 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	0	0	0	1	4
80% and < 90%	0	1	1	0	0	6
75% and < 80%	0	0	0	0	0	3
70% and < 75%	0	0	0	0	0	4
60% and < 70%	0	0	0	1	0	9
50% and < 60%	0	0	0	0	1	9
25% and < 50%	0	0	0	0	1	26
10% and < 25%	0	0	5	2	5	34

Table C-32 Offer-capped unit statistics: 2016

	2016 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	1	1	1	0	0	0
80% and < 90%	0	0	1	1	1	0
75% and < 80%	0	0	0	0	1	1
70% and < 75%	1	0	0	0	1	0
60% and < 70%	1	0	0	0	0	2
50% and < 60%	1	0	0	0	0	2
25% and < 50%	1	3	0	4	2	24
10% and < 25%	0	0	1	2	8	21

Table C-33 Offer-capped unit statistics: 2017

	2017 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	1	1	1	1
80% and < 90%	0	0	1	2	0	1
75% and < 80%	0	0	0	1	1	0
70% and < 75%	1	0	0	0	0	1
60% and < 70%	0	0	0	0	1	1
50% and < 60%	0	0	0	1	0	1
25% and < 50%	1	0	1	1	6	31
10% and < 25%	0	0	1	1	14	36

Energy Uplift

Credits and Charges to Generators

Table C-34 and Table C-35 compare the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table C-34 shows that on average, 10.5 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, were paid by generators deviating in the Eastern Region while these generators received 50.7 percent of all balancing generator credits.

Table C-34 Monthly balancing operating reserve charges and credits to generators in the Eastern Region (Millions): 2016

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$0.4	$0.0	$0.1	$0.5	$5.5
Feb	$0.1	$0.0	$0.0	$0.1	$0.8
Mar	$0.2	$0.0	$0.1	$0.3	$1.9
Apr	$0.1	$0.0	$0.1	$0.2	$1.2
May	$0.3	$0.0	$0.2	$0.5	$2.3
Jun	$0.3	$0.1	$0.2	$0.5	$2.5
Jul	$0.3	$0.1	$0.1	$0.5	$4.2
Aug	$0.3	$0.0	$0.1	$0.3	$2.6
Sep	$0.4	$0.0	$0.1	$0.5	$5.4
Oct	$0.3	$0.1	$0.1	$0.5	$3.3
Nov	$0.4	$0.1	$0.1	$0.6	$3.2
Dec	$0.4	$0.3	$0.4	$1.1	$8.8
East Generators Total	$3.5	$0.7	$1.5	$5.7	$41.6
PJM Total	$36.0	$3.5	$14.7	$54.2	$82.0
Share	9.7%	19.8%	10.1%	10.5%	50.7%

Table C-35 shows that generators in the Western Region paid 10.6 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 47.4 percent of all balancing generator credits.

Table C-35 Monthly balancing operating reserve charges and credits to generators in the Western Region (Millions): 2017

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$0.5	$0.0	$0.1	$0.6	$1.9
Feb	$0.1	$0.0	$0.0	$0.1	$0.5
Mar	$0.2	$0.0	$0.1	$0.3	$3.3
Apr	$0.1	$0.0	$0.1	$0.2	$1.8
May	$0.3	$0.0	$0.2	$0.5	$4.6
Jun	$0.3	$0.0	$0.2	$0.5	$3.9
Jul	$0.3	$0.0	$0.2	$0.5	$3.3
Aug	$0.3	$0.0	$0.1	$0.4	$2.7
Sep	$0.4	$0.1	$0.2	$0.6	$4.6
Oct	$0.4	$0.0	$0.1	$0.5	$4.6
Nov	$0.5	$0.0	$0.1	$0.6	$3.6
Dec	$0.4	$0.0	$0.3	$0.7	$4.0
West Generators Total	$3.8	$0.1	$1.5	$5.5	$38.9
PJM Total	$36.0	$0.8	$14.7	$51.4	$82.0
Share	10.6%	18.0%	10.2%	10.6%	47.4%

Table C-36 shows that on average in 2017, energy uplift charges paid by generators were 8.6 percent of all energy uplift charges, 0.2 percentage point higher than the average in 2016. Generators received 99.7 percent of all energy uplift credits, while the remaining 0.3 percent of credits were paid to import transactions and demand resources.

Table C-36 Percentage of generators credits and charges of total credits and charges: 2016 and 2017

	2016		2017	
	Generators Share of Total Energy Uplift Charges	Generators Share of Total Energy Uplift Credits	Generators Share of Total Energy Uplift Charges	Generators Share of Total Energy Uplift Credits
Jan	8.2%	99.4%	9.4%	99.9%
Feb	8.3%	99.9%	2.5%	99.9%
Mar	5.9%	100.0%	9.0%	99.8%
Apr	11.4%	99.9%	8.4%	99.1%
May	8.6%	99.9%	9.8%	99.6%
Jun	9.9%	99.9%	10.4%	99.2%
Jul	10.8%	99.9%	8.6%	99.7%
Aug	11.3%	99.7%	7.3%	99.5%
Sep	8.5%	99.9%	7.5%	99.3%
Oct	7.8%	100.0%	8.6%	100.0%
Nov	3.7%	100.0%	9.7%	100.0%
Dec	5.6%	99.9%	9.6%	100.0%
Average	8.4%	99.8%	8.6%	99.7%

Energy Uplift Charges by Transaction/Resource Type

Table C-37 shows the energy uplift charges and applicable rates for each type of resource or transaction in PJM.

Table C-37 Energy uplift charge by transaction/resource type

		Transaction / Resource Type									
Charge	Rate	Load	Generation	Imports[1]	Exports[1]	Wheels	Economic DR	INCs	DECs	IBTs	UTCs
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X				X		
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X						
	Regional (East or West) Reliability Rate	X			X						
Balancing Operating Reserves for Deviations[2]	RTO Deviation Rate	X	X	X	X		X	X	X	X	
	Regional (East or West) Deviation Rate	X	X	X	X		X	X	X	X	
	LOC Rate	X	X	X	X		X	X	X	X	
	Canceled Resources Rate	X	X	X	X		X	X	X	X	
Reactive Services	Implicit Rates	X									
Black Start Services	Implicit Rates	X[3]		X[4]	X[4]	X[4]					
Synchronous Condensing	Implicit Rate	X			X						

1 Dynamic scheduled transactions are exempt from operating reserve charges.

2 Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.

3 Load is charged black start services based on their zonal peak load contribution.

4 Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

Appendix D Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether structural market power requires offer capping to prevent the potential exercise of local market power for binding constraints.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2017, through December 31, 2017. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Until November 1, 2017, only uncommitted resources, started to relieve the transmission constraint, were subject to offer capping. Resources that were committed economically, that were ramped up to provide incremental relief for a binding constraint, could not be switched from the schedule that they were operating on. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time), to provide relief for a constraint, can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be cheaper than the price-based offer. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that did result in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

The three pivotal supplier test is calculated as part of the Intermediate Term Security Constrained Economic Dispatch (IT SCED) tool. IT SCED looks ahead at multiple intervals up to two hours ahead, and forecasts potential binding constraints and suggests unit commitment and dispatch changes to meet transmission limits. As a result the remedial actions taken in advance in response to IT SCED forecasts, the set of constraints that appear to be potentially binding in IT SCED is not necessarily the same as the set of constraints that bind in the Real-Time SCED tool. This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours in real time. In 2017, the AEP, APS, ATSI, BGE, ComEd, Dominion, DPL, Met-Ed, PECO, PENELEC, PPL, and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for 2017, actual competitive conditions associated with each of these frequently binding constraints were analyzed for the Real Time Energy Market. The AECO, DAY, DEOK, DLCO, EKPC, JCPL, Pepco, and RECO control zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping and the number of tests that did result in offer capping. Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

AEP Control Zone Results

In 2017, there was one constraint that occurred for more than 100 hours in the AEP Control Zone. Table D-1 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-1 shows that for the Logtown - North Delphos constraint in the AEP Zone, there was one owner, on average, with available supply to relieve the constraint.

Table D-1 Three pivotal supplier test details for constraints located in the AEP Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Logtown - North Delphos	Peak	7	56	1	0	1
	Off Peak	8	58	1	0	1

Table D-2 shows the total tests applied for the constraint in the AEP Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D- 2 shows that for the Logtown - North Delphos constraint in the AEP Zone, zero percent of the total tests applied resulted in offer capping.

Table D-2 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AEP Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Logtown - North Delphos	Peak	1,249	0	0%	0	0%	NA
	Off Peak	1,399	0	0%	0	0%	NA

APS Control Zone Results

In 2017, there was one constraint that occurred for more than 100 hours in the APS Control Zone. Table D-3 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-3 shows that for the Butler - Shanor Manor constraint in the APS Zone, there were 11 owners on peak, and 10 owners off peak, on average, with available supply to relieve the constraint.

Table D-3 Three pivotal supplier test details for constraints located in the APS Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Butler - Shanor Manor	Peak	64	72	11	1	10
	Off Peak	60	60	10	1	10

Table D-4 shows the total tests applied for the constraint in the APS Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-4 shows that for the Butler - Shanor Manor constraint in the APS Zone, zero percent of the total tests applied resulted in offer capping.

Table D-4 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the APS Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Butler - Shanor Manor	Peak	1,534	1,334	87%	3	0%	0%
	Off Peak	1,072	1,019	95%	0	0%	0%

ATSI Control Zone Results

In 2017, there were two constraints in the ATSI Control Zone that occurred for more than 100 hours. Table D-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-5 shows that for the Lakeview – Greenfield constraint in the ATSI Zone, there were less than three owners, on average, with available supply to relieve the constraint.

Table D-5 Three pivotal supplier test details for constraints located in the ATSI Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lakeview - Greenfield	Peak	35	28	2	0	2
	Off Peak	27	22	2	0	2
Nottingham	Peak	58	84	10	3	6
	Off Peak	99	123	10	2	8

Table D-6 shows the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for constraints in the ATSI Zone. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-6 shows that zero percent of the tests applied resulted in offer capping for both the constraints.

Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ATSI Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Lakeview - Greenfield	Peak	850	37	4%	0	0%	0%
	Off Peak	360	54	15%	0	0%	0%
Nottingham	Peak	1,887	806	43%	1	0%	0%
	Off Peak	1,022	218	21%	0	0%	0%

BGE Control Zone Results

In 2017, there were three constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-7 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-7 shows that for all three of the constraints in the BGE Zone, there were at least eleven owners, on average, with available supply to relieve the constraint.

Table D-7 Three pivotal supplier test details for constraints located in the BGE Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bagley - Graceton	Peak	100	142	14	2	11
	Off Peak	83	143	12	4	8
Conastone - Northwest	Peak	69	118	11	3	8
	Off Peak	92	131	11	3	8
Graceton - Safe Harbor	Peak	79	112	13	2	11
	Off Peak	72	108	12	2	11

Table D-8 shows the total tests applied for the three constraints in the BGE Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-8 shows that two percent or fewer of the tests applied to the constraints in the BGE Zone resulted in offer capping.

Table D-8 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Bagley - Graceton	Peak	936	659	70%	11	1%	2%
	Off Peak	515	314	61%	8	2%	3%
Conastone - Northwest	Peak	1,992	938	47%	13	1%	1%
	Off Peak	847	598	71%	5	1%	1%
Graceton - Safe Harbor	Peak	4,627	3,370	73%	29	1%	1%
	Off Peak	8,127	5,032	62%	39	0%	1%

ComEd Control Zone Results

In 2017, there were nine constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-9 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-9 shows that for all nine constraints in the ComEd Zone, on average, the number of owners with available supply was less than four.

Table D-9 Three pivotal supplier test details for constraints located in the ComEd Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Braidwood - East Frankfort	Peak	44	69	2	0	2
	Off Peak	30	72	1	0	1
Cherry Valley	Peak	18	29	2	0	2
	Off Peak	14	26	1	0	1
Cherry Valley - Belvidere	Peak	11	23	2	0	2
	Off Peak	12	22	2	0	2
Dresden	Peak	14	18	2	0	2
	Off Peak	12	22	2	0	2
Fisk	Peak	24	27	1	0	1
	Off Peak	22	49	1	0	1
Haumesser Road - Steward	Peak	19	50	2	0	2
	Off Peak	20	55	2	0	2
Mazon - Crescent Ridge	Peak	7	14	2	0	2
	Off Peak	5	14	2	0	2
Nelson	Peak	21	33	1	0	1
	Off Peak	16	24	1	0	1
Powerton - Goodings Grove	Peak	46	167	1	0	1
	Off Peak	33	149	1	0	1

Table D-10 shows the total tests applied for the nine constraints in the ComEd Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-10 shows that for all constraints, zero percent of the tests applied resulted in offer capping.

Table D-10 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Braidwood - East Frankfort	Peak	1,739	490	28%	1	0%	0%
	Off Peak	2,128	263	12%	4	0%	2%
Cherry Valley	Peak	887	52	6%	0	0%	0%
	Off Peak	317	8	3%	0	0%	0%
Cherry Valley - Belvidere	Peak	514	35	7%	0	0%	0%
	Off Peak	400	26	7%	0	0%	0%
Dresden	Peak	523	90	17%	0	0%	0%
	Off Peak	11	1	9%	0	0%	0%
Fisk	Peak	89	50	56%	0	0%	0%
	Off Peak	5	0	0%	0	0%	NA
Haumesser Road - Steward	Peak	927	4	0%	0	0%	0%
	Off Peak	1,102	1	0%	0	0%	0%
Mazon - Crescent Ridge	Peak	371	82	22%	0	0%	0%
	Off Peak	530	13	2%	0	0%	0%
Nelson	Peak	441	59	13%	0	0%	0%
	Off Peak	132	4	3%	0	0%	0%
Powerton - Goodings Grove	Peak	515	0	0%	0	0%	NA
	Off Peak	858	0	0%	0	0%	NA

Dominion Control Zone Results

In 2017, there were two constraints that occurred for more than 100 hours in the Dominion Control Zone. Table D-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-11 shows that for both the constraints in the Dominion Zone, on average, there were six or more owners with available supply to relieve the constraint.

Table D-11 Three pivotal supplier test details for constraints located in the Dominion Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carson - Rawlings	Peak	122	234	6	0	6
	Off Peak	95	173	7	0	7
Person - Sedge Hill	Peak	72	75	6	1	5
	Off Peak	80	70	6	0	6

Table D-12 shows the total tests applied for the two constraints in the Dominion Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-12 shows that two percent or fewer of the tests applied to the constraints in the Dominion Zone resulted in offer capping.

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Carson - Rawlings	Peak	1,694	1,630	96%	24	1%	1%
	Off Peak	563	547	97%	7	1%	1%
Person - Sedge Hill	Peak	1,541	1,314	85%	19	1%	1%
	Off Peak	601	522	87%	14	2%	3%

DPL Control Zone Results

In 2017, there was one constraint that occurred for more than 100 hours in the DPL Control Zone. Table D-13 shows the average constraint relief required on the Kenney - Stockton constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-13 shows that for the Kenney - Stockton constraint in the DPL Zone, on average, the number of owners with available supply was one.

Table D-13 Three pivotal supplier test details for constraints located in the DPL Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kenney - Stockton	Peak	43	44	1	0	1
	Off Peak	27	28	1	0	1

Table D-14 shows the total tests applied for the six constraints in the DPL Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-14 shows that zero percent of the tests applied to the constraints in the DPL zone resulted in offer capping.

Table D-14 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DPL Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Kenney - Stockton	Peak	1,221	858	70%	6	0%	1%
	Off Peak	1,351	1,316	97%	3	0%	0%

MetEd Control Zone Results

In 2017, there was one constraint that occurred for more than 100 hours in the MetEd Control Zone. Table D-15 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-15 shows that for the Gardners – Texas East constraint in the MetEd Zone, on average, the number of owners with available supply was one.

Table D-15 Three pivotal supplier test details for constraints located in the MetEd Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Gardners - Texas East	Peak	18	15	1	0	1
	Off Peak	14	9	1	0	1

Table D-16 shows the total tests applied for the constraints in the MetEd Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-16 shows that one percent of the tests applied to the Gardners – Texas East constraint in the MetEd Zone resulted in offer capping.

Table D-16 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the MetEd Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Gardners - Texas East	Peak	727	261	36%	6	1%	2%
	Off Peak	117	45	38%	1	1%	2%

PECO Control Zone Results

In 2017, there were two constraints that occurred for more than 100 hours in the PECO Control Zone. Table D-17 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-17 shows that for all two constraints in the PECO Zone, on average, the number of owners with available supply was three or less.

Table D-17 Three pivotal supplier test details for constraints located in the PECO Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Chichester - Foulke	Peak	46	73	3	0	3
	Off Peak	39	84	2	0	2
Emilie - Falls	Peak	26	41	3	0	3
	Off Peak	18	40	2	0	2

Table D-18 shows the total tests applied for the constraints in the PECO Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-18 shows that zero percent of the tests applied to the constraints in the PECO Zone resulted in offer capping.

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PECO Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Chichester - Foulke	Peak	627	53	8%	0	0%	0%
	Off Peak	141	2	1%	0	0%	0%
Emilie - Falls	Peak	6,586	2,747	42%	12	0%	0%
	Off Peak	1,948	351	18%	5	0%	1%

PENELEC Control Zone Results

In 2017, there were eight constraints that occurred for more than 100 hours in the PENELEC Control Zone. Table D-19 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-19 shows that for seven out of the eight constraints in the PENELEC Zone, on average, the number of owners with available supply was three or less.

Table D-19 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carlisle Pike - Roxbury	Peak	20	21	1	0	1
	Off Peak	12	16	1	0	1
East Sayre - East Towanda	Peak	17	38	3	0	3
	Off Peak	17	34	3	0	3
East Towanda - Hillside	Peak	36	144	2	0	2
	Off Peak	46	137	2	0	2
East Towanda - North Meshoppen	Peak	13	28	2	0	2
	Off Peak	12	34	2	0	2
North Meshoppen	Peak	11	26	3	0	3
	Off Peak	10	35	2	0	2
North Meshoppen - Oxbow	Peak	52	82	6	0	6
	Off Peak	20	83	3	0	3
Saxton - Three Springs	Peak	12	6	3	0	3
	Off Peak	15	6	3	0	3
South Troy - Tennessee Gas Tap	Peak	9	36	3	0	3
	Off Peak	10	41	3	0	2

Table D-20 shows the total tests applied for the constraints in the PENELEC Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-20 shows that one percent or fewer of the tests applied to the constraints in the PENELEC Zone resulted in offer capping.

Table D-20 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PENELEC Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Carlisle Pike - Roxbury	Peak	231	62	27%	0	0%	0%
	Off Peak	13	6	46%	0	0%	0%
East Sayre - East Towanda	Peak	1,786	1,150	64%	1	0%	0%
	Off Peak	1,113	498	45%	0	0%	0%
East Towanda - Hillside	Peak	1,569	898	57%	0	0%	0%
	Off Peak	1,317	123	9%	0	0%	0%
East Towanda - North Meshoppen	Peak	2,839	1,847	65%	5	0%	0%
	Off Peak	2,528	1,627	64%	9	0%	1%
North Meshoppen	Peak	613	326	53%	0	0%	0%
	Off Peak	803	74	9%	0	0%	0%
North Meshoppen - Oxbow	Peak	757	625	83%	4	1%	1%
	Off Peak	811	247	30%	0	0%	0%
Saxton - Three Springs	Peak	835	182	22%	8	1%	4%
	Off Peak	332	65	20%	2	1%	3%
South Troy - Tennessee Gas Tap	Peak	283	81	29%	0	0%	0%
	Off Peak	639	126	20%	0	0%	0%

PPL Control Zone Results

In 2017, there were two constraints that occurred for more than 100 hours in the PPL Control Zone. Table D-21 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-21 shows that for the Conastone – Otter Creek Line, on average, there were 20 owners on peak and nineteen owners off peak with available supply to relieve the constraint.

Table D-21 Three pivotal supplier test details for constraints located in the PPL Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Conastone - Otter Creek	Peak	118	196	20	5	15
	Off Peak	128	211	19	5	14
Quarry - Steel City	Peak	96	126	1	0	1
	Off Peak	95	127	1	0	1

Table D-22 shows the total tests applied for the two constraints in the PPL Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-22 shows that three percent or fewer of the tests applied to the Conastone – Otter Creek Constraint in the PPL Zone resulted in offer capping.

Table D-22 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PPL Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Conastone - Otter Creek	Peak	3,390	3,018	89%	94	3%	3%
	Off Peak	6,516	5,357	82%	28	0%	1%
Quarry - Steel City	Peak	2,209	52	2%	0	0%	0%
	Off Peak	1,116	15	1%	0	0%	0%

PSEG Control Zone Results

In 2017, there was one constraint that occurred for more than 100 hours in the PSEG Control Zone. Table D-23 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-23 shows that for the Kilmer - Sayreville line, on average, there were four owners on peak and three owners off peak with available supply to relieve the constraint.

Table D-23 Three pivotal supplier test details for constraints located in the PSEG Control Zone: 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kilmer - Sayreville	Peak	40	142	4	0	3
	Off Peak	41	78	3	0	3

Table D-24 shows the total tests applied for the Kilmer - Sayreville constraint in the PSEG Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are economically committed, that are ramped up to provide incremental relief during their original commitment, cannot be offer capped. Table D-24 shows that one percent or fewer of the tests applied to the Kilmer - Sayreville constraint in the PSEG Zone resulted in offer capping.

Table D-24 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Kilmer - Sayreville	Peak	1,682	715	43%	6	0%	1%
	Off Peak	324	125	39%	2	1%	2%

Appendix E Interchange Transactions

Submitting Transactions into PJM

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements. Unfortunately, interface prices are not well designed and result in incentives to engage in transactions that are not efficient and would not occur if there were a single set of consistent LMPs across all interconnected markets.

The institutional details of completing import and export transactions include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Energy Market

Market participants that wish to transact energy into, out of, or through PJM in the Real-Time Energy Market are required to make their requests to PJM via a NERC Interchange Transaction Tag (NERC Tag). PJM's External Scheduling software (ExSchedule) interfaces with NERC Tags to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer), an aggregate of generation supply (aggregate offer) or an external market (pool supplied). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to four hours prior to the scheduled start time for transactions that are more than 24 hours in duration.[2] Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1800 (EPT) the day prior to the scheduled start time. Schedules utilizing firm point to point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point to point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure that the energy profile and path match. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1800 (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

With the implementation of the coordinated transaction scheduling (CTS) product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, will PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process violates ramp, PJM makes additional adjustments on a

1 The material in this section is based in part on PJM's Regional Transmission and Energy Scheduling Practices Document. See PJM. "Regional Transmission and Energy Scheduling Practices," Version 26 (October 3, 2017). <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

2 PJM ended the requirement for a day-ahead checkout for real-time transactions. Previously, for a schedule to be included in PJM's day-ahead checkout process, the NERC Tag had to have been approved by all entities who had approval rights, and be in a status of "Implemented," by 1400 (EPT) one day prior to start of schedule.

last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until they have completed their economic evaluation and are approved through the NYISO market clearing process. The MMU has not observed any adverse effects of the new process. The MMU will continue to monitor and evaluate the process.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[3] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, nonfirm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Nonfirm.** Point to point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Nonfirm point to point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for non-load serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

3 For additional details see PJM. "Regional Transmission and Energy Scheduling Practices," Version 26 (October 6, 2017). <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Source and Sink

For real-time import and export energy transactions, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source and sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source and sink would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) or Load Control Area (LCA) on the NERC Tag represents physical flow entering or leaving PJM at an interface other than the default interface pricing point, the source or sink would be assigned the new interface pricing point reflecting the interface pricing point where the physical energy enters or leaves the PJM footprint.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When ExSchedule detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in ExSchedule specifying "Real-Time with Price" and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the "Pending Tag" status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in ExSchedule, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to zero MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Transfers[4]

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource's output be electronically moved from the PJM Region (native BA) to another balancing authority (receiving BA). An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource's output be electronically removed from its balancing authority to the PJM Region. This is referred to as a dynamic transfer. Dynamic transfers include dynamic schedules and pseudo ties.

Dynamic Schedule

A dynamic schedule is a time varying energy transfer that is updated in real time and included in scheduled net interchange in the same way as an interchange schedule in the Area Control Error (ACE) equation for both balancing authorities. A dynamically scheduled resource remains within its native balancing authority's metered boundary while providing services to the receiving balancing authority. A dynamic schedule is modeled as an interchange schedule, and therefore is subject to NERC Tagging requirements.

4 The material in this section is based in part on PJM's Manual 12: Balancing Operations. See PJM. "PJM Manual 12: Balancing Operations," Rev. 38 (April 20, 2018) <http://www.pjm.com/~/media/documents/manuals/m12.ashx >.

Pseudo Tie

A pseudo tie is a time varying energy transfer that is updated in real-time and included in actual net interchange in the same way as a tie line in the ACE equation. A pseudo tie is accounted for as actual interchange. A pseudo tied resource is considered to be within the receiving BA's metered boundary, and must therefore be modeled in the receiving BA's Energy Management System (EMS). Pseudo ties are usually not subject to NERC Tagging because they are part of congestion management procedures, like the PJM/MISO Market to Market Congestion Management Agreement.

Pseudo ties must register with the North American Energy Standards Board (NAESB) to assist with interregional coordination management. Pseudo ties are subject to NERC Tagging requirements unless the pseudo-tie is included in congestion management procedures.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an "Implemented" status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected interchange for the next hour.

Real-Time with Price Evaluation and Checkout

Real-time with Price schedules, dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since Real-Time with Price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed when there is, or is expected to be, realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or nonfirm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[5]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse impact on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater

5 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) <http://www.nerc.com/files/IRO-006-4.pdf>.

than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.

- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.
- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point to point transmission service on a pro rata basis to allow additional interchange transactions using firm point to point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using nonfirm point to point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point to point transmission service, to flow.
- **TLR Level 5b – Curtail transactions using firm point to point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using nonfirm point to point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.
- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both nonfirm and firm point to point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table E-1 below shows the number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Table E-1 TLRs by level and reliability coordinator: 2004 through 2017

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total	Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154	2011	ICTE	23	12	123	54	48	0	260
	FPL	0	1	0	0	0	0	1		MISO	92	30	1	9	9	0	141
	IMO	33	2	0	0	0	0	35		NYIS	161	0	0	0	0	0	161
	MAIN	8	3	0	0	0	0	11		ONT	88	0	0	0	0	0	88
	MISO	650	210	409	9	3	0	1,281		PJM	34	28	0	0	0	0	62
	PJM	270	115	35	4	5	0	429		SWPP	292	298	1	25	22	0	638
	SOCO	1	0	0	0	0	0	1		TVA	75	99	9	2	15	0	200
	SWPP	185	107	14	5	6	0	317		VACS	9	3	0	0	0	0	12
	TVA	56	17	0	0	1	0	74	Total		774	470	134	90	94	0	1,562
	VACN	8	1	0	0	0	0	9									
Total		1,258	471	546	19	18	0	2,312	2012	ICTE	25	7	11	63	40	0	146
										MISO	75	26	0	16	43	0	160
2005	EES	49	10	101	6	3	1	170		NYIS	60	0	0	0	0	0	60
	IMO	57	2	0	0	0	0	59		ONT	47	1	0	0	0	0	48
	MISO	776	296	200	5	14	0	1,291		PJM	18	19	0	0	0	0	37
	PJM	201	94	29	1	1	0	326		SOCO	0	1	0	0	0	0	1
	SWPP	193	78	19	4	2	0	296		SWPP	248	165	5	78	33	0	529
	TVA	172	61	12	2	3	0	250		TVA	55	32	9	7	5	0	108
	VACN	0	3	0	0	0	0	3		VACS	6	4	0	0	0	0	10
	VACS	2	2	0	1	0	0	5	Total		534	255	25	164	121	0	1,099
Total		1,450	546	361	19	23	1	2,400									
									2013	ICTE	0	0	0	0	0	0	0
2006	EES	71	20	93	5	1	0	190		MISO	119	48	2	128	73	0	370
	ICTE	11	6	14	0	1	0	32		NYIS	3	0	0	0	0	0	3
	IMO	1	0	0	0	0	0	1		ONT	7	0	0	0	0	0	7
	MISO	414	214	136	17	19	0	800		PJM	25	22	0	1	1	0	49
	ONT	27	3		0	0	0	30		SOCO	0	0	0	0	0	0	0
	PJM	88	30	18	0	0	0	136		SWPP	342	114	0	76	24	0	556
	SWPP	189	121	201	11	13	0	535		TVA	29	26	2	5	5	0	67
	TVA	90	52	31	1	2	0	176		VACS	5	7	0	0	0	0	12
	VACS	0	1	0	0	0	0	1	Total		530	217	4	210	103	0	1,064
Total		891	447	493	34	36	0	1,901									
									2014	MISO	63	45	1	16	16	0	141
2007	ICTE	95	42	139	19	10	0	305		NYIS	2	0	0	0	0	0	2
	MISO	414	273	89	17	26	0	819		ONT	3	0	0	0	0	0	3
	ONT	47	4	1	0	0	0	52		PJM	3	3	0	1	1	0	8
	PJM	46	31	1	1	1	0	80		SOCO	4	1	0	0	0	0	5
	SWPP	777	935	35	53	24	0	1,824		SWPP	260	80	0	54	34	0	428
	TVA	45	40	25	2	2	0	114		TVA	31	40	2	25	34	0	132
	VACS	4	1	0	0	0	0	5		VACS	7	16	3	2	0	0	28
Total		1428	1326	290	92	63	0	3,199	Total		373	185	6	98	85	0	747
2008	ICTE	132	41	112	43	25	0	353	2015	MISO	28	32	0	16	12	0	88
	MISO	320	235	21	8	15	0	599		NYIS	4	0	0	0	0	0	4
	ONT	153	7	1	0	0	0	161		ONT	3	1	0	0	0	0	4
	PJM	55	92	2	0	1	0	150		PJM	13	7	0	1	1	0	22
	SWPP	687	1,077	11	59	44	0	1,878		SOCO	0	0	0	0	0	0	0
	TVA	48	72	29	5	4	0	158		SWPP	102	59	0	32	19	0	212
Total		1,395	1,524	176	115	89	0	3,299		TVA	36	64	0	24	36	0	160
										VACS	0	2	0	0	1	0	3
2009	ICTE	82	35	55	75	18	1	266	Total		186	165	0	73	69	0	493
	MISO	199	140	2	15	25	0	381									
	NYIS	101	8	0	0	0	0	109	2016	MISO	33	21	0	8	15	0	77
	ONT	169	0	0	0	0	0	169		NYIS	1	0	0	0	0	0	1
	PJM	61	68	0	0	0	0	129		ONT	10	0	0	0	0	0	10
	SWPP	383	1,466	33	77	24	0	1,983		PJM	4	3	0	1	1	0	9
	TVA	8	22	29	0	0	0	59		SOCO	0	1	0	0	0	0	1
	VACS	0	1	0	0	0	0	1		SWPP	54	23	0	45	22	0	144
Total		1,003	1,740	119	167	67	1	3,097		TVA	41	65	0	4	18	0	128
										VACS	1	1	0	0	0	0	2
2010	ICTE	72	25	149	50	30	0	326	Total		144	114	0	58	56	0	372
	MISO	123	93	0	15	18	0	249									
	NYIS	104	0	0	0	0	0	104	2017	MISO	42	16	0	10	7	0	75
	ONT	94	5	0	1	0	0	100		NYIS	1	0	0	0	0	0	1
	PJM	65	45	0	0	0	0	110		ONT	6	0	0	0	0	0	6
	SWPP	244	1,049	19	63	32	0	1,407		PJM	4	2	0	0	0	0	6
	TVA	37	64	8	1	6	0	116		SOCO	1	4	0	0	0	0	5
	VACS	1	1	0	0	0	0	2		SWPP	34	4	0	54	19	0	111
Total		740	1,282	176	130	86	0	2,414		TVA	13	11	0	2	5	0	31
										VACS	3	3	0	0	0	0	6
									Total		104	40	0	66	31	0	241

Day-Ahead Energy Market

For day-ahead market scheduling, ExSchedule serves only as an interface to the eMKT application. Day-ahead market transactions are evaluated in the Day-Ahead Energy Market, and the results sent to ExSchedule. No checkout is performed on day-ahead market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Energy Market Schedules

Market participants can submit day-ahead market schedules to the eMKT application through ExSchedule. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-ahead market schedules require an OASIS number to be associated upon submission.[6] The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[7]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[8] The NYISO requires bids or offer prices for each export or import transaction and clears its market for each 15 minute interval based on bids.[9] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each 15 minute interval. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the Real-Time Commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single 15 minute increment.

Under PJM operating practices, in the Real-Time Energy Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[10] The duration of the requested transaction can vary from 15 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than one percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

6 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additionally, effective May 15, 2012, up to congestion transactions were required to be submitted for the PJM day-ahead market evaluation in the eMarket application, and are no longer accepted through the EES application. Additional details can be found under the "Up to Congestion" heading in *Section 9: Interchange Transactions* of this report.

7 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

8 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

9 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf>.

10 See PJM. "Regional Transmission and Energy Scheduling Practices," Version 26 (October 6, 2017). <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating 15 minute interval. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

Appendix F Ancillary Service Markets

This appendix covers five areas related to Ancillary Service Markets: area control error, Control Performance Standard 1 and Balancing Authority ACE Limit, Disturbance Control Standard (DCS), Primary Frequency Response, Regulation Market design changes, and the Synchronized Reserve Market clearing process.

Area Control Error (ACE)

Area control error (ACE) is a real-time measure of the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. The metrics for success in balancing ACE are control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).[2]

In the absence of a severe grid disturbance, the primary tool used by dispatchers to control ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[3]

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL)

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL) are the NERC metrics for the effectiveness of power balance through ACE control. The goal of ACE control is to maintain power balance and interconnection frequency within predefined MW and frequency profiles under all conditions (normal and abnormal).

Frequency (as it applies to the electric power grid) is the rate at which alternating current cycles between minimum and maximum. Usually this is 60 Hz (one Hz is one cycle per second). PJM measures the instantaneous frequency every two seconds. Frequency changes when there is an imbalance between generation and load causing a mismatch between actual and scheduled tie-line flow. PJM dispatchers seek to minimize this deviation. If the mismatch persists, a time error can accumulate.

Frequency bias is a physical attribute of a control area. It is defined as the natural response in MW of that control area (at estimated yearly peak demand) to a change in frequency of 0.1 Hz.[4] NERC requires each balancing authority to review and report its frequency bias by January 1 each year.

CPS1/BAAL are performance standards used to measure and report how well PJM accomplishes ACE and frequency balance. CPS1 is defined according to NERC Standard BAL-001-0.1a.[5] BAAL is defined according to NERC Standard BAL-001-2.[6]

NERC Standard BAL-001-0.1a Real Power Balancing Control Performance

NERC Standard BAL-001-0.1a requires PJM "[t]o maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time."[7] Meeting the CPS1 standard requires PJM dispatchers to maintain ACE within a fixed range around zero.

1 The PJM Manuals define ACE and the methodology for calculating it: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions–the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively.", "PJM Manual 12: Balancing Operations," Revision 38 (April 20, 2018), para. 3.1.1, "PJM Area Control Error", p. 12.

2 NERC standard BAL-001-0.1a "Real Power Balancing Control Performance," <http://www.nerc.com/pa/stand/reliability%20standards%20complete%20set/rscompleteset.pdf>.

3 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 97 (July 26, 2018), pp. 55.

4 See Frequency Response and Bias Standard BAL-003-0.1a <http://www.nerc.com/files/BAL-003-0_1a.pdf>.

5 NERC Standard BAL-001-0.1a Real Power Balancing Control Performance <http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-1.pdf>

6 BAL-001-2 – Real Power Balancing Control Performance Standard Background Document, Feb 2013 <http://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf>

7 See PJM. "Manual 12: Balancing Operations," Revision 38 (April 20, 2018), Section 3, "NERC Control Performance Standard" pg. 20.

CPS1

CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute and averaged over a year. CPS1 is defined as:

> "the average of the clock-minute averages of a Balancing Area's ACE divided by minus 10 B (where B is Balancing Area frequency bias) times the corresponding clock-minute averages of the Interconnection's frequency error must be less than a specific limit. This limit, 'ε', is a constant derived from a targeted frequency bound (limit) that is reviewed and set, as necessary, by NERC."[8]

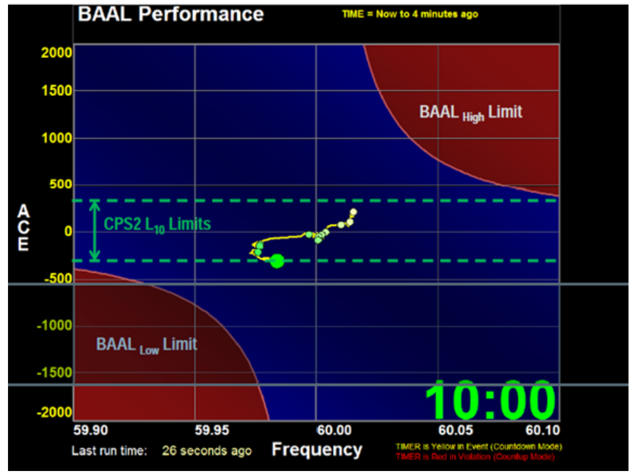
CPS1 is calculated as CPS1 = (2-CF)*100%. The frequency related compliance factor (CF) is a ratio of the accumulating clock-minute compliance parameters for the most recent twelve consecutive calendar months, divided by the square of the target frequency bound (ε1i). The ε1i value for the Eastern Interconnection is 0.018 Hz. It can be seen from this equation that if the yearly one-minute average deviations (CF) were zero the CPS1 score would be a perfect 200 percent. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

The defined fixed range for the 2017 and 2018 operating years (+/- 258.2 MW/0.1Hz) is called L_{10}. Compliance with the CPS1 standard requires that 90 percent of 10-minute periods have an average ACE value within the L_{10} range. The L_{10} was last changed on December 1, 2016. Previously it had been +/-263.15 MW/0.1Hz.

BAAL

The other NERC standard for maintaining power balance is the Balancing Authority ACE Limit (BAAL), which replaced the old CPS2. BAAL is a measure of the relationship between frequency and ACE such that both must remain within the blue area in Figure E-1. The $BAAL_{High}$ and $BAAL_{Low}$ limits are curves which are functions of measured frequency and scheduled frequency.

Figure E-1 Example set of BAAL measurements: Set of measurements is every two seconds for four minutes



PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month. BAAL high and low limits are defined dynamically.[9]

When actual frequency is less than Scheduled Frequency, $BAAL_{High}$ does not apply, and $BAAL_{Low}$ is calculated as:

$$BAAL_{Low} = \left(-10B_i \times (FTL_{Low} - F_S)\right) \times \frac{(FTL_{Low} - F_S)}{(F_A - F_S)}$$

When actual frequency is greater than Scheduled Frequency, $BAAL_{Low}$ does not apply and the $BAAL_{High}$ is calculated as:

$$BAAL_{High} = \left(-10B_i \times (FTL_{High} - F_S)\right) \times \frac{(FTL_{High} - F_S)}{(F_A - F_S)}$$

$BAAL_{Low}$ is the Low Balancing Authority ACE Limit (MW), $BAAL_{High}$ is the High Balancing Authority ACE Limit (MW), 10 is a constant to convert the Frequency Bias Setting from MW/0.1 Hz to MW/Hz, B_i is the Frequency Bias Setting for a Balancing Authority (expressed as MW/0.1 Hz), F_A is the measured frequency in Hz, F_S is the scheduled frequency in Hz, FTL_{Low} is the Low Frequency Trigger Limit (calculated as F_S - 3ε1I Hz), and FTL_{High} is the High Frequency Trigger Limit (calculated as FS + 3ε1I Hz). The constant ε1I

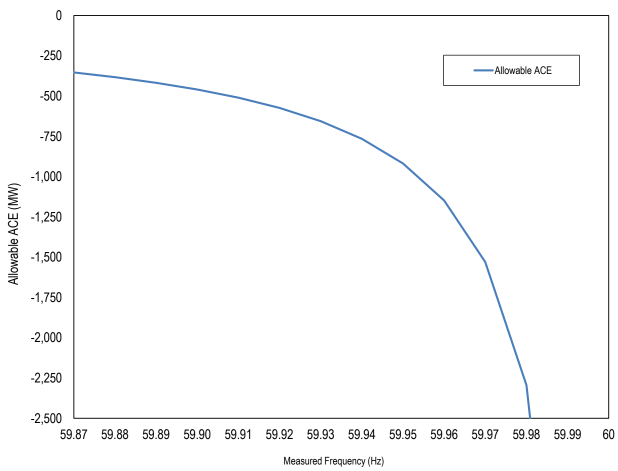
8 See PJM. "Manual 12: Balancing Operations," Revision 38 (April 20, 2018), Section 3, "NERC Control Performance Standard" pg. 21.

9 NERC BAL-001-2, Real Power Balancing Control Performance. Feb. 2013.

is derived from a targeted frequency bound for each Interconnection as follows: Eastern Interconnection ε1I is 0.018 Hz, Western Interconnection ε1I is 0.0228 Hz, ERCOT Interconnection ε1I is 0.030 Hz, and Quebec Interconnection ε1I is 0.021 Hz.

Figure E-2 shows the relationship of measured frequency to allowable ACE deviation when measured frequency is less than scheduled frequency (defined by the $BAAL_{Low}$ equation, scheduled frequency = 60 Hz and negative ACE only). As the measured frequency approaches the scheduled frequency (typically 60 Hz), the allowable ACE increases in absolute value.

Figure E-2 Allowable ACE as a function of measured frequency

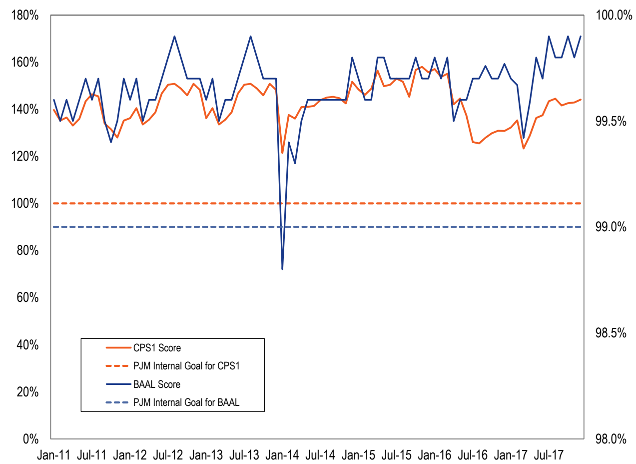


As an example consider a single 2-second measurement under the following scenario. The frequency bias is calculated by PJM each year. PJM's current frequency bias (for December 1, 2016, through November 30, 2017) is -1,015 MW/0.1Hz. PJM's frequency profile calls for a scheduled frequency of 60 Hz (this can be changed by PJM dispatch under certain circumstances). Under this scenario, applying the formula for $BAAL_{Low}$ shows that ACE needs to be greater than -493.8975 MW at a real-time frequency of 59.92 Hz in order for this one measurement to be within acceptable BAAL limits. A complete scenario is provided by adding the ACE deviation for measured frequency greater than scheduled frequency $BAAL_{High}$ (Figure E-1).

PJM's CPS/BAAL Performance

The BAAL standard set by NERC states that, "the clock-minute average of Reporting ACE does not exceed its clock-minute limit for more than 30 consecutive clock-minutes."[10] PJM has set an internal standard that measures the total number of minutes that ACE complies with the BAAL limits and divides it by the total number of minutes over the entire month, with a passing level set at 99.0 percent for each month. Figure E-3 shows PJM's CPS1 and BAAL performance from January 2011 through December 2017. PJM did not meet its internal goal for BAAL performance in January 2014, however PJM has remained in compliance with the applicable NERC standards since January 2011, for compliance for both CPS1 and BAAL metrics.

Figure E-3 PJM CPS1/BAAL performance: January 2011 through December 2017



PJM's DCS Performance

The NERC disturbance control standard (DCS) measures how well ACE recovers from a disturbance.[11] A disturbance is defined by NERC as any ACE deviation caused by sudden loss of generation greater than, or equal to, 80 percent of PJM's most severe single contingency loss. Disturbance control is measured and must be reported to NERC quarterly as percentage of recovery (R_i) as defined below.

If ACE was positive or zero just before the disturbance then ACE must be returned to zero within fifteen minutes. Full disturbance recovery within fifteen minutes represents 100 percent performance under this

10 See PJM. "Manual 12: Balancing Operations," Revision 38 (April 20, 2018), Section 3.1.1, pg. 21.
11 For more information on the NERC DCS, see "Standard BAL-002-0 – Disturbance Control Performance" (4/1/ 2012) <www.nerc.com/files/BAL-002-0.pdf>.

measure. Less than full recovery in fifteen minutes earns a score defined as:

$$R_i = \left(\frac{MW_{loss} - \max(0, ACE_a - ACE_m)}{MW_{loss}}\right) * 100\%$$

If ACE was negative just before the disturbance then ACE must be returned to its pre-disturbance value. Full disturbance recovery within fifteen minutes represents 100 percent performance under this measure. Less than full recovery in fifteen minutes earns a score as per:

$$R_i = \left(\frac{MW_{loss} - \max(0, -ACE_m)}{MW_{loss}}\right) * 100\%$$

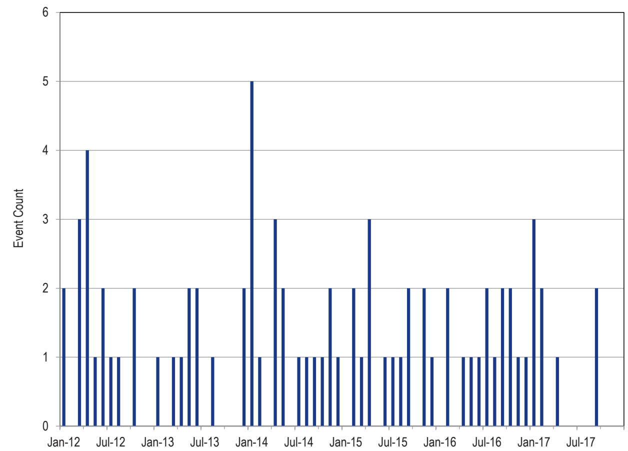
Where MW_{loss} is the MW size of the disturbance from the beginning of the loss, ACE_a is the pre-disturbance ACE, ACE_m is the maximum algebraic value of the ACE measured within fifteen minutes following the disturbance.

PJM experienced 45 DCS events in 2015, 2016 and 2017. PJM DCS compliance has remained at 100% since 2011. (Figure E-4)

Although PJM recovered from all DCS events by declaring a synchronized reserve event, not all synchronized reserve events are caused by DCS events. DCS events are "sudden unanticipated losses of supply-side resources."[12] Several significant synchronized reserve events in 2013 and 2014, most notably the 68 minute event of September 10, 2013, the 33 minute event of October 28, 2013, and the 34 minute event of January 7, 2014 were caused by low ACE and were therefore not reportable as DCS events. There were five low ACE events in 2017, including the 16 minute event on September 21, 2017. There have been 23 spinning events between January 2013 and December 2017 caused by Low ACE.

12 Standard BAL-002-0 – Disturbance Control Performance," (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB) para. 1.4, pag. 4.

Figure E-4 DCS event count (By month): January 2012 through December 2017



Primary Frequency Response

On November 17, 2016, FERC issued as Primary Frequency Response notice of proposed rulemaking (NOPR).[13] The NOPR proposed a regulation requiring all new generating facilities, both synchronous and non-synchronous to install and enable primary frequency response capability as a condition of interconnection. Nuclear units are exempted from this NOPR. Existing units are exempted from this NOPR.

The NOPR proposed that all newly interconnecting generating facilities to install and enable primary frequency response capability that would allow a maximum five percent droop; a +/- 0.036 Hz deadband setting; and automated timely and sustained response to frequency deviations.[14]

The FERC standard is documented in NERC Reliability Standard BAL-003-1, Frequency Response and Frequency Bias Setting. PJM participated in a field trial for this standard in 2016. PJM is currently conducting studies to define primary frequency events, compliance metrics, and requirement standards. A Markets and Reliability Task Force is evaluating PJM Operating Agreement, Tariff, and manuals for additional language.

13 157 FERC ¶ 61,122

14 Droop percentage is defined as ((generator speed at no load) – (generator speed at full load)) / (generator speed at no load). The NOPR requires that these parameters be based on nameplate capability.

Regulation Market Design Changes

On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to include fast response in addition to traditional regulation resources."[15]

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the fast and slow resources be purchased in a single market, with compensation for both capacity (MW) and miles (ΔMW).[16] Regulation miles are calculated as the sum of the absolute value of a given regulation resource's movement (up and down) in response to a regulation signal.

To incorporate the new fast regulation, PJM developed a fast regulation signal (RegD) that responds faster to changes in ACE than the traditional slow regulation signal (RegA). Resources are free to choose which signal they will follow. A study by KEMA for PJM indicated that including a combination of RegA and RegD following resources in the Regulation Market would allow PJM to reduce its regulation requirement but still maintain CPS1 scores close to the historical average (significantly above the passing score of 100 percent).[17]

According to the study, the smaller the proportion of RegD MW and the greater the proportion of RegA, the greater the benefit to adding one more MW of RegD. The smaller the proportion of fast regulation used, the more slow regulation each MW of fast regulation can replace. Conversely, as the proportion of fast regulation increases, there is a decrease in the benefit of substituting fast capability for slow capability. This rate of substitution between fast and slow resources is the marginal benefit factor or MBF. The marginal benefit factor measures the equivalent MW of slow regulation that can be displaced by one MW of fast regulation. If one MW of fast regulation can replace two MW of slow regulation while maintaining the same overall regulation performance, the marginal benefit factor is 2.0. The marginal benefit factor decreases as the amount of fast resources increases. RegD MW additions are allowed (if economic) until the MBF is zero, at which point one MW of RegD does not reduce the amount of RegA needed to maintain the same overall regulation performance. Past this point, the addition of another MW of fast capability results in a MBF less than zero. An MBF less than zero means that adding another MW of fast regulation requires the addition of slow regulation in order to maintain a regulation performance target. At this point the rate of substitution is negative and the addition of fast resources makes it harder to maintain a regulation performance target.[18] It is possible for PJM to achieve a passing CPS1 score (100 percent) entirely with slow regulation resources as PJM has done since its inception, but PJM cannot achieve a passing CPS1 score using only fast regulation resources.

- **PJM monitors compliance using the current regulation signals CRegA and CRegD.** The CRegA signal tracks compliance with the RegA signal and the CRegD signal tracks compliance with the RegD signal. The current regulation signals CRegA and CRegD are calculated every two seconds as the sum of the response of a regulation resource (an individual resource or a fleet of resources). The current regulation signals CRegA and CRegD are a measure of real time regulation feedback sent to PJM to determine if and to what degree the regulation signals RegA and RegD are being followed.[19] Figure E-5 shows a screenshot of a typical 10-minute time period of PJM's RegA signal and CRegA signal for all RegA resources. Figure E-6 shows a screenshot of typical 10-minute time period of PJM's RegD signal and CRegD signal for all RegD resources.

15 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."

16 Id. at PP 99, 131 & 177.

17 See KEMA. "KERMIT Study Report," (December 13, 2011).

18 PJM calculates a marginal benefit factor using a function that is arbitrarily defined to have zero as its lower bound. The practical impact of this incorrect functional form is likely to be negligible in the near term because substantially more RegD resources would have to be added to result in a negative marginal benefit factor but the function should be corrected. See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Revision 97 (July 26, 2018), 3.2.7 p 76.

19 See PJM. "Manual 12: Balancing Operations," Revision 38 (April 20, 2018), 4.4.2 p 47.

Figure E-5 PJM RegA signal and CReg compliance signal. Example of typical 10-minute time period

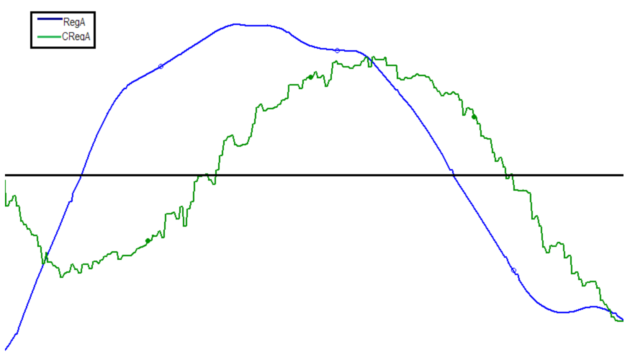
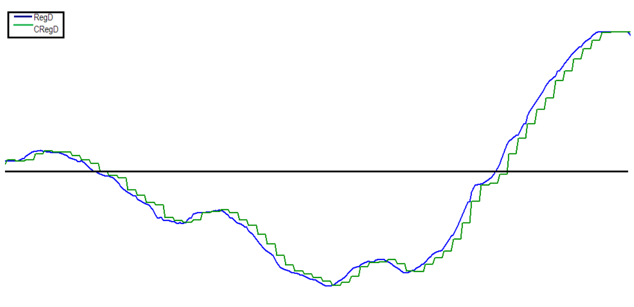


Figure E-6 PJM RegD signal and CRegD current regulation signal. Example of typical 10-minute time period



Regulation signals are designed for the purpose of moderating ACE, accounting for the characteristics of the expected response from the resources following the signal. The RegD signal is designed to contribute to the moderation of ACE given the attributes of fast regulation resources. The RegA signal is designed to contribute to the moderation of ACE given the attributes of traditional sources of regulation. Even a very fast regulating unit will need to have some capability to provide sustained MWh to help with ACE correction, and even a unit with a large MW capability must be able to react with some speed to help with ACE correction. The relationship between the two types of regulating resources is under constant review and the relationship between the two (the marginal benefit factor) is subject to change.

- **Regulation Offers.** All owners of generating and demand resources qualified to provide regulation may offer their regulation capability price in $/MW at cost plus up to $12 adder daily into the Regulation Market using the PJM market user interface. There is no must offer requirement for resources qualified to provide regulation. Users must also enter the signal type they want to follow (RegA or RegD), their regulation capability in MW, as well as cost validation parameters including fuel cost, heat rate at economic maximum, heat rate at regulation minimum, and the VOM rate. Regulating units may also self schedule. Self scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Owners may also enter price based offers up to a maximum of $100/MW. Demand resources are eligible to offer regulation and did so for the first time in November 2011. Demand resources have an LOC of zero. Under current PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources.[20] Total regulation offers are the sum of all regulation capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to “unavailable” for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. All regulation offers that are not set to unavailable for the day are summed to calculate the total daily regulation offered, a figure that changes each hour.
- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs the Ancillary Services Optimizer software (ASO) to determine the amount of Tier 2 synchronized reserve/nonsynchronized reserve required, develop regulation and synchronized reserve supply curves, and assign regulation, synchronized reserve, and nonsynchronized reserve to specific units. All regulation resource units which have made offers in the daily Regulation Market are evaluated by ASO for regulation. ASO excludes units according to the following ordered criteria: daily or hourly unavailable status; units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-

20 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Revision 97 (July 26, 2018), 3.2.4 p 62.

scheduled regulation); units assigned synchronized reserve; units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); units that are offline (except combustion turbine units).[21]

- **Regulation Market Clearing and Dispatch.** The Regulation Market is cleared by the ASO sixty minutes before the operational hour. The specific units scheduled to regulate are selected at that time based on the lowest price set of units sufficient to fill the regulation requirement. The actual unit dispatch happens at the start of the operational hour and is under the control of unit operators. The final Regulation Market Clearing Price used to settle the regulation market is based on the costs and LMPs of the units that are actually dispatched. Differences between market clearing and market dispatch can cause unnecessary uplift payments or a final price paid to all units based on a less than optimal set of dispatched regulating units.

Even after ASO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically to provide regulation for several reasons including: to control transmission constraints; to avoid over-generation during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.[22]

For each offered and eligible unit in the regulation supply, the regulation total capability offer price is calculated using the sum of the unit's regulation cost-based offer (divided by the marginal benefit factor of the resource type and the historic performance score of the resource) plus the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. Based on this result, ASO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. ASO uses price-based offers for those operators not offer capped and re-solves. Unit assignments based on this solution are final. The final clearing price is not determined at the time of unit assignment.

The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared, prior to the hour, and supplementally within the hour, on a real-time basis. The Regulation, Synchronized Reserve, and Nonsynchronized Reserve Markets are cleared and priced interactively with the energy market and secondary reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements, reserve requirements and prior to the hour assignments for regulation and reserves.[23] The final clearing prices are calculated at five-minute intervals based on the real-time prices and LMPs of energy. These five-minute prices are averaged to arrive at the final hourly clearing price. This price is sent to Settlements and used and the basis for credits and charges.

- **Cleared Regulation.** Regulation actually assigned by ASO is cleared regulation. The capability and performance prices are calculated every five minutes by the Locational Pricing Calculator (LPC) with the final hourly clearing price averaged from the five minute prices. In real time, resources that have been assigned an ancillary service are expected to provide that ancillary service for the designated hour.
- **Settled Regulation.** Owners of regulation resources are compensated by RMCP (Regulation Market Clearing Price) credits and opportunity cost credits. RMCP credits are the sum of RMCCP (Regulation Market Capability Clearing Price) credits and RMPCP (Regulation Market Performance Clearing Price) credits. RMCCP credits are calculated as MW of regulation capability times the performance score times RMCCP. For RegA resources, RMPCP credits are calculated as MW of regulation capability times performance score times RMPCP. For RegD resources, RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. When calculating RMCCP and RMPCP credits, the MW of regulation capability are defined as the actual MW provided (as opposed to cleared MW or effective MW). The owner of a regulation resource receives

21 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Revision 97 (July 26, 2018), 2.5 p 44.
22 See PJM. " Manual 11: Energy & Ancillary Services Markets Operations," Revision 97 (July 26, 2018), 3.1 p 64.
23 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Revision 97 (February 1, 2017), 5.2.4 p 110.

opportunity cost credits only if its RMCP credits are less than its offer plus opportunity cost (including lost opportunity cost during shoulder hours). The cost per actual MW of settled regulation can be higher than the regulation clearing price because actual MW and cleared MW may differ and RMCP credits may not completely cover lost opportunity costs.

Synchronized Reserve Market Clearing

PJM's market clearing engines consider resources capable of providing Tier 2 synchronized reserve to be either flexible or inflexible. CTs operating below their economically desired MW will sometimes be dispatched flexibly intra hour. Hydro resources are often a source of flexible T2. Inflexible units are scheduled by the hourly market solution sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus LOC (demand response resources are paid SRMCP). Demand response resources are defined to be inflexible. Flexible units are identified and may be scheduled every time the market solution runs (hour ahead, intermediate term, and short term) and can be assigned to either synchronized reserve or to energy depending on the economic solution. This flexibility allows for a less expensive hourly cost when intrahour events such as constraints binding, changes in imports or exports and performance problems occur.

In the Mid-Atlantic Dominion Subzone, the market for Tier 2 synchronized reserve is cleared in four steps.

One hour before the market hour, ASO estimates the sum of the available Tier 1 synchronized reserve within the MAD Subzone and the available transfer capacity from outside the MAD Subzone. ASO subtracts this estimated sum from the MAD Subzone synchronized reserve requirement to determine the amount of MAD Tier 2 synchronized reserve needed to satisfy the requirement. If the synchronized reserve requirement is not filled from available Tier 1 and imports then self-scheduled Tier 2 synchronized reserve is assigned. If the required synchronized reserve is still not satisfied, ASO clears a market for inflexible synchronized reserve. Tier 2 synchronized reserve flexible resources can be changed throughout the hour by both the intermediate term and short term market clearing software.

Half an hour before the market hour, the intermediate term solution (IT SCED) performs the same functions as ASO up to the point of logging and committing individual resources, taking into account the amount of inflexible resources already committed by ASO. After IT SCED produces its solution, a PJM operator reviews the solution, calls the inflexible resources to commit them to provide Tier 2 synchronized reserve, and logs each resource separately. As with ASO, the amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Fifteen minutes before each 5-minute period in the market hour, real-time solution (RT SCED) estimates the amount of needed Tier 2 synchronized reserve, taking into account the amount of inflexible resources already committed by ASO and IT SCED. RT SCED considers only flexible resources due to the notification-time requirements of inflexible resources. Once RT SCED generates its solution, RT SCED commits the resources from its solution and logs these resources.

Every 5 minutes within the market hour, LPC calculates market clearing prices by incorporating resource offers and LOC based on real-time LMP and the cost of the marginal unit. LPC computes the price of Tier 2 synchronized based on these factors and the committed resources and uses this price as the within-hour five-minute clearing price. For the hour, the Synchronized Reserve Market Clearing Price is the simple average of the twelve 5-minute clearing prices. When there is a simultaneous shortage of primary reserve and synchronized reserves the real-time prices for synchronized reserve will be the sum of the primary reserve and synchronized reserve penalty factors.[24]

Whereas the hourly price is the average of the five-minute prices within the hour, the hourly cost (per MW) is the sum of credits for cleared and self-scheduled synchronized reserve and credits for after market lost opportunity cost divided by the total MW of synchronized reserve cleared and self-scheduled. PJM guarantees resources to be made whole to their offer plus opportunity costs.

24 See PJM. "Manual 11: Energy & Ancillary Services Markets Operations," Revision 97 (July 20, 2018), p. 95.

Appendix G Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.[1] SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Total system-wide transmission losses for 2017 were 14,920.1 GWh, a 1.5 percent decrease compared to 2016. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints. Congestion is defined to be load payments in excess of generation revenues. Congestion revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3]

Congestion Costs

Zonal Congestion Costs

Positive or negative CLMPs caused by a specific constraint at a specific bus indicate whether that constraint is increasing or decreasing the LMP at that bus relative to the system marginal price. The total CLMP at a specific bus is the net sum of the positive and negative CLMPs caused by all binding constraints at that bus.

CLMPs are not congestion. CLMPs are a component of price paid by or to load and generation.

Congestion revenues are defined to be equal to the sum of day ahead and balancing congestion. Day-ahead and balancing congestion costs by zone for 2017 and 2016 are presented in Table G-1 and Table G-2. While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear congestion costs.

Load congestion payments, when positive, measure the congestion cost to load in an area. Load congestion payments, when negative, measure the congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South Interface means lower prices in western control zones and higher prices in eastern and

1 For more information about LMP see the *Technical Reference for PJM Markets*, "Calculating Locational Marginal Price," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

3 The total congestion and marginal losses were calculated as of January 18, 2018, and are subject to change, based on continued PJM billing updates.

southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the congestion credit to generation in an area. Positive generation congestion credits result when generation is on the higher priced side of a constraint or constraints. Generation congestion credits, when negative, measure the congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints.

For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for the buses in that zone, not including explicit congestion.

Because the net congestion bill for a zone only includes charges or credits incurred within the zone, the congestion bill for the zone is not a good measure of the amount of congestion (the difference between what load is pays and generation is paid) incurred by that zone's load. Zonal congestion calculations do not, for example, account for the total difference between what the zonal load is paying in congestion charges relative to what the generation that serves that load if the zone is a net importer or a net exported of generation. Zonal congestion calculated for a zone that is a net importer of generation will tend to have overstated congestion, as the calculation does not account for external generation credits from external generation used to serve that load. Zonal congestion calculated for a zone that is a net exporter of generation will tend to have overstated generation congestion credits, as the calculation does not account for only that generation used to meet the zone's internal load.

The ComEd Control Zone, Dominion Control Zone and the AEP Control Zone are examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The ComEd Control Zone had the highest congestion charges, $215.8 million, of any control zone in 2017. The positive congestion costs in the ComEd Control Zone were the result of negative load congestion payments offset by larger negative generation congestion credits. Thus, the lower prices in ComEd, which resulted from a lower congestion component of LMP, meant that load paid lower prices and lower congestion, and that generators received lower prices and a lower congestion component. The result was positive measured congestion costs. This result follows from the fact that total zonal load is less than total zonal generation because the zone is a net exporter. In 2017, the total ComEd zonal generation was 128,205.5 GWh and total zonal load was 94,325.9 GWh in the real-time market, compared to 125,121.6 GWh generation and 95,391.1 GWh load in the day-ahead market.

The AEP Control Zone had the second highest congestion charges, $90.9 million, of any control zone in 2017. The positive congestion costs in the AEP Control Zone were the result of positive load congestion payments offset by negative generation congestion credits.

The PECO Control Zone had the third highest congestion charges, $73.1 million, of any control zone in 2017. The positive congestion costs in the PECO Control Zone were the result of negative load congestion payments offset by larger negative generation congestion credits.

The PENELEC Control Zone had the fourth highest congestion charges, $52.4 million, of any control zone in 2017. The positive congestion costs in the PENELEC Control Zone were the result of negative load congestion payments offset by larger negative generation congestion credits.

The Dominion Control Zone had the fifth highest congestion charges, $51.0 million, of any control zone in 2017. The positive congestion costs in the Dominion Control Zone were the result of positive load congestion payments offset by smaller positive generation congestion credits.

The External category is not a control zone. The External category is comprised of external pricing points (buses) associated with interfaces.[4] The total congestion cost for the external category was -$13.9 million in 2017.

Table G-1 Congestion cost summary (By control zone): 2017

Congestion Costs (Millions)									
	Day-Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	($21.8)	($18.7)	($0.5)	($3.6)	$1.0	$2.1	$1.0	($0.0)	($3.6)
AEP	($10.2)	($108.9)	($1.9)	$96.8	$14.4	$12.0	($8.2)	($5.8)	$90.9
APS	$23.9	$4.6	($1.6)	$17.7	$1.5	$0.7	$2.4	$3.2	$20.9
ATSI	$13.3	($8.5)	$4.3	$26.2	$0.6	$4.7	($4.4)	($8.6)	$17.7
BGE	$131.8	$94.5	$8.9	$46.2	($1.1)	($1.0)	($6.5)	($6.7)	$39.5
ComEd	($237.6)	($467.3)	($16.3)	$213.4	$0.1	$7.1	$9.4	$2.4	$215.8
DAY	$0.5	$0.5	$0.7	$0.7	$1.0	$0.8	($1.3)	($1.2)	($0.5)
DEOK	$19.7	$0.9	$1.9	$20.7	($0.5)	($0.6)	($4.0)	($3.9)	$16.8
DLCO	$3.6	$3.9	$1.0	$0.7	($0.2)	($0.0)	($1.3)	($1.5)	($0.8)
DPL	$12.5	$16.2	($0.1)	($3.9)	($3.2)	($14.6)	($1.6)	$9.8	$5.9
Dominion	$372.9	$313.9	$6.1	$65.1	($0.3)	$7.1	($6.6)	($14.0)	$51.0
EKPC	($8.1)	($2.3)	($0.2)	($6.0)	$1.6	($0.1)	$0.4	$2.1	($3.9)
External	($15.5)	($12.7)	($4.0)	($6.8)	($6.8)	$0.6	$0.2	($7.2)	($13.9)
JCPL	($31.5)	($37.5)	($0.9)	$5.0	$3.8	$3.5	$0.6	$0.9	$5.9
Met-Ed	($4.8)	($25.4)	($1.1)	$19.5	($0.1)	$2.0	$2.5	$0.5	$19.9
PECO	($78.6)	($154.5)	($2.0)	$73.9	$4.9	$7.1	$1.3	($0.8)	$73.1
PENELEC	($64.4)	($123.4)	($4.1)	$54.9	$1.2	$8.8	$5.2	($2.5)	$52.4
PPL	($57.5)	($91.1)	($3.4)	$30.3	$3.9	$6.6	$5.1	$2.4	$32.7
PSEG	($28.7)	($69.8)	$2.2	$43.3	$1.6	$4.2	($2.8)	($5.4)	$37.9
Pepco	$169.1	$131.7	$2.5	$39.9	($1.4)	($3.8)	($1.8)	$0.7	$40.6
RECO	($1.0)	($0.0)	$0.1	($0.9)	$0.2	$0.0	($0.1)	$0.0	($0.8)
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6

Table G-2 Congestion cost summary (By control zone): 2016

Congestion Costs (Millions)									
	Day-Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	($34.4)	($28.7)	$3.6	($2.0)	$1.1	$1.3	($2.3)	($2.6)	($4.6)
AEP	$44.9	($83.3)	$9.1	$137.4	($6.4)	$8.7	($13.9)	($29.0)	$108.4
APS	$48.7	$8.5	($0.9)	$39.2	($1.0)	$0.3	$4.5	$3.2	$42.4
ATSI	($6.6)	($20.4)	$4.5	$18.4	$0.6	$0.0	($2.6)	($1.9)	$16.4
BGE	$398.9	$278.1	$17.4	$138.1	($6.7)	($12.1)	($14.7)	($9.3)	$128.8
ComEd	($157.1)	($495.6)	($4.2)	$334.3	$1.6	$23.6	($8.6)	($30.7)	$303.6
DAY	($3.9)	($2.8)	$0.8	($0.3)	($0.2)	($0.2)	($1.2)	($1.1)	($1.5)
DEOK	$9.5	($1.6)	$3.6	$14.6	($0.4)	($0.6)	($3.0)	($2.8)	$11.8
DLCO	($0.9)	($3.3)	$0.7	$3.1	$0.1	$0.0	($0.9)	($0.8)	$2.3
DPL	$8.3	$7.7	$1.6	$2.2	($1.8)	($13.2)	($1.0)	$10.4	$12.6
Dominion	$568.1	$499.1	$4.9	$73.9	($2.8)	$2.3	($3.1)	($8.2)	$65.7
EKPC	($4.0)	($2.8)	$0.9	($0.3)	($2.0)	($0.5)	($1.3)	($2.8)	($3.1)
External	($36.8)	($23.6)	($3.8)	($17.0)	($7.2)	$5.7	$3.5	($9.4)	($26.4)
JCPL	($95.3)	($86.4)	($1.9)	($10.7)	$4.1	$3.1	$0.9	$1.9	($8.9)
Met-Ed	($56.1)	($99.5)	($2.0)	$41.4	$1.0	$5.6	$2.3	($2.2)	$39.2
PECO	($177.6)	($311.9)	($4.4)	$129.9	$5.9	$6.5	$5.3	$4.7	$134.6
PENELEC	($99.2)	($143.6)	$3.2	$47.6	$1.0	$6.4	($2.9)	($8.3)	$39.4
PPL	($176.7)	($214.1)	($2.7)	$34.8	$3.0	$8.2	$2.9	($2.3)	$32.4
PSEG	($180.8)	($209.5)	$4.1	$32.8	$3.8	($8.6)	($2.2)	$10.2	$43.0
Pepco	$361.3	$280.1	$6.7	$87.9	$1.5	($8.4)	($5.3)	$4.5	$92.4
RECO	($5.2)	($0.6)	($0.2)	($4.8)	$0.3	$0.3	($0.2)	($0.2)	($5.0)
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$1,023.7

4 The new external pricing points associated with interfaces can be found at the following link. <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Details of Regional and Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM West Region with eight control zones (the APS, ATSI, ComEd, AEP, DLCO, DEOK, DAY and EKPC control zones); and the PJM South Region with one control zone (the Dominion Control Zone).[5]

Table G-3 through Table G-42 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2017 and 2016. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. The tables present the constraints in descending order of the absolute value of total congestion costs for each zone. In addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. In 2017, the RECO Control Zone only had two internal constraints, thus the RECO table shows the top 15 constraints and two local constraints.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table G-3 AECO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	($6.8)	($5.0)	($0.1)	($1.9)	$0.2	$0.4	$0.1	($0.0)	($1.9)	6,318	1,680
2	Graceton - Safe Harbor	Line	BGE	($4.2)	($2.9)	($0.1)	($1.4)	$0.1	$0.3	$0.1	($0.1)	($1.5)	6,236	2,302
3	5004/5005 Interface	Interface	500	$2.6	$1.6	$0.0	$1.0	$0.1	$0.0	($0.0)	$0.0	$1.1	346	208
4	Conastone - Otter Creek	Line	PPL	($3.0)	($2.4)	($0.1)	($0.6)	$0.1	$0.4	$0.1	($0.3)	($0.9)	2,672	1,736
5	Conastone - Northwest	Line	BGE	($1.9)	($1.6)	($0.0)	($0.4)	$0.1	$0.2	$0.1	($0.0)	($0.5)	1,950	456
6	Butler - Shanor Manor	Line	APS	($1.9)	($1.5)	($0.0)	($0.4)	$0.1	$0.1	$0.0	$0.0	($0.4)	3,768	530
7	Three Mile Island	Transformer	500	($2.0)	($1.6)	($0.1)	($0.4)	$0.0	$0.0	$0.1	$0.1	($0.4)	1,080	172
8	Brunner Island - Yorkanna	Line	Met-Ed	($1.1)	($0.8)	($0.0)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	1,362	148
9	Pleasant View - Ashburn	Line	Dominion	($0.6)	($0.4)	($0.0)	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	946	170
10	Churchtown	Transformer	AECO	$0.1	($0.1)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	440	0
11	Roxana - Praxair	Flowgate	MISO	$0.7	$0.4	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	3,468	580
12	Cedar Grove - Clifton	Line	PSEG	($0.5)	($0.3)	($0.1)	($0.2)	($0.0)	$0.1	$0.1	$0.0	($0.2)	2,358	158
13	Bagley - Graceton	Line	BGE	($0.7)	($0.5)	($0.0)	($0.2)	$0.0	$0.1	$0.0	($0.0)	($0.2)	1,108	254
14	Edge Moor - Harmony	Line	DPL	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.2	$0.2	$0.2	152	98
15	Monroe - Vineland	Line	AECO	$0.2	$0.1	$0.1	$0.2	($0.0)	($0.0)	($0.1)	($0.1)	$0.2	686	26
18	Mickleton - River	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	240	0
19	Sherman - Vineland	Line	AECO	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	846	0
20	Chambers	Transformer	AECO	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,274	0
28	Cumberland - Sherman Avenue	Line	AECO	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	484	0
50	Butler - Sherman	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	436	0

5 See "Operating Agreement of PJM Interconnection, L.L.C.," (June 1, 2017) Section OA 1. DEFINITIONS <http://www.pjm.com/documents/agreements.aspx>

Table G-4 AECO Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Monroe - Vineland	AECO	$12.1	$7.9	$4.6	$8.8	($1.2)	($2.2)	($3.6)	($2.6)	$6.2	10,708	878
2	AP South	Conastone - Northwest	BGE	($17.0)	($13.2)	($0.4)	($4.2)	$0.7	$1.2	$0.4	($0.0)	($4.2)	5,552	3,680
3	Bedington - Black Oak	Graceton	BGE	($10.6)	($7.6)	($0.2)	($3.3)	$0.1	$0.3	$0.3	$0.1	($3.2)	6,234	2,596
4	Person - Halifax	Bagley - Graceton	BGE	($11.2)	($8.7)	($0.3)	($2.9)	$0.5	$0.6	$0.3	$0.1	($2.7)	6,626	3,370
5	Loudoun	Conastone - Peach Bottom	500	($5.0)	($4.5)	($0.2)	($0.7)	$0.3	$0.4	$0.2	$0.0	($0.6)	4,814	1,398
6	502 Junction	Conastone - Otter Creek	PPL	($1.5)	($1.2)	($0.0)	($0.3)	$0.1	$0.2	$0.0	($0.1)	($0.4)	618	316
7	Bagley - Graceton	Brambleton - Loudoun	Dominion	$0.9	$0.7	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	760	62
8	Graceton	Bagley - Raphaerd	BGE	($1.2)	($0.9)	($0.0)	($0.3)	$0.0	$0.1	$0.0	($0.0)	($0.3)	1,208	462
9	Brambleton - Loudoun	Emilie - Falls	PECO	($0.3)	($0.5)	$0.0	$0.2	($0.0)	$0.0	$0.1	$0.0	$0.2	5,234	658
10	Person - Halifax	Person - Halifax	MISO	$0.6	$0.4	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	1,438	10
11	Kanawha	Plymouth Meeting - Whitpain	PECO	$1.4	$1.3	$0.1	$0.2	($0.0)	($0.1)	($0.0)	($0.0)	$0.2	770	58
12	Meadow Brook - Strasburg	Conastone - Graceton	BGE	($0.8)	($0.6)	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.2)	1,230	398
13	Roxbury	Coolspring - Milford	DPL	($0.3)	($0.1)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	1,124	90
14	Yukon	Nottingham	PECO	($0.2)	($0.1)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	418	0
15	Brambleton - Mosby	Milford - Steele	DPL	($0.4)	($0.3)	($0.1)	($0.2)	$0.0	$0.0	$0.1	$0.0	($0.1)	3,028	530
19	All Dam - Kittanning	Second Street - Sherman Ave	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	6
23	Butler - Karns City	Monroe - Tansboro	AECO	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	34	0
27	St. Marys - Pleasants	Clayton - Woodstown	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	66	0
32	Muskingum - Wolf Creek	Churchtown	AECO	$0.0	($0.1)	$0.1	$0.1	$0.1	$0.1	($0.3)	($0.2)	($0.1)	776	106
36	Klinesmill - Riverton	Lewis - Mill	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.2)	($0.2)	($0.1)	180	4

BGE Control Zone

Table G-5 BGE Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Graceton - Safe Harbor	Line	BGE	$23.9	$15.7	$2.3	$10.5	($1.0)	($0.2)	($2.0)	($2.9)	$7.7	6,236	2,302
2	Conastone - Northwest	Line	BGE	$13.0	$7.8	$0.7	$5.9	($0.2)	($0.2)	($0.5)	($0.5)	$5.4	1,950	456
3	Conastone - Peach Bottom	Line	500	$19.7	$16.0	$1.5	$5.3	($0.6)	($0.2)	($0.9)	($1.4)	$3.9	6,318	1,680
4	Riverside	Line	BGE	$2.4	($0.2)	$0.2	$2.9	$0.0	($0.0)	($0.1)	($0.0)	$2.9	502	20
5	Conastone - Otter Creek	Line	PPL	$13.6	$10.9	$1.1	$3.9	($0.2)	($0.2)	($1.2)	($1.3)	$2.6	2,672	1,736
6	Bagley - Graceton	Line	BGE	$5.7	$3.7	$0.5	$2.5	($0.2)	($0.1)	($0.3)	($0.5)	$2.0	1,108	254
7	Brunner Island - Yorkanna	Line	Met-Ed	$4.4	$3.1	$0.3	$1.6	($0.0)	($0.0)	($0.1)	($0.1)	$1.5	1,362	148
8	Face Rock	Other	PPL	$2.8	$1.7	$0.2	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1,070	0
9	5004/5005 Interface	Interface	500	$3.7	$2.5	($0.2)	$0.9	$0.2	($0.1)	$0.1	$0.4	$1.4	346	208
10	Nottingham	Other	PECO	$2.3	$1.3	$0.3	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	2,130	0
11	Butler - Shanor Manor	Line	APS	($3.9)	($2.7)	($0.2)	($1.3)	$0.1	$0.1	$0.1	$0.2	($1.1)	3,768	530
12	BCPEP	Interface	Pepco	$3.0	$2.1	$0.3	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	1,114	0
13	Brandon Shores - Riverside	Line	BGE	$0.5	($0.5)	$0.1	$1.0	$0.0	($0.0)	($0.1)	($0.0)	$1.0	248	12
14	Pleasant View - Ashburn	Line	Dominion	($3.8)	($2.9)	($0.2)	($1.0)	$0.1	$0.2	$0.1	$0.1	($1.0)	946	170
15	Middletown Jct - Brunner Island	Line	PPL	$1.8	$0.9	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	1,186	0
19	Bagley - Raphaerd	Line	BGE	$1.9	$1.3	$0.1	$0.7	($0.0)	($0.0)	($0.0)	($0.0)	$0.7	344	98
26	Conastone - Graceton	Line	BGE	$0.8	$0.5	$0.1	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	172	20
28	Brandon Shores - Waugh Chapel	Line	BGE	$0.4	$0.1	$0.1	$0.4	($0.0)	($0.1)	($0.1)	($0.1)	$0.3	236	14
39	Glenarm - Windy Edge	Line	BGE	$0.7	$0.5	$0.1	$0.3	$0.0	$0.1	($0.1)	($0.1)	$0.2	396	76
40	Center - Westport	Line	BGE	$0.1	($0.0)	$0.0	$0.2	$0.1	($0.0)	($0.1)	($0.0)	$0.2	154	10

Table G-6 BGE Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Graceton	Transformer	BGE	$105.2	$64.4	$4.7	$45.4	($1.6)	($4.9)	($3.5)	($0.2)	$45.3	6,234	2,596
2	Conastone - Northwest	Line	BGE	$108.9	$82.3	$4.0	$30.6	($1.6)	($3.7)	($3.4)	($1.3)	$29.2	5,552	3,680
3	Bagley - Graceton	Line	BGE	$77.2	$59.7	$3.6	$21.1	($2.3)	($2.4)	($2.9)	($2.8)	$18.3	6,626	3,370
4	Center - Westport	Line	BGE	$10.0	$1.7	$0.5	$8.8	($1.2)	($0.1)	($1.0)	($2.1)	$6.7	1,492	234
5	Brandon Shores - Riverside	Line	BGE	$7.2	$1.2	$0.3	$6.2	($0.2)	($0.5)	($0.5)	($0.3)	$5.9	426	82
6	Riverside	Line	BGE	$3.9	($0.2)	$0.4	$4.5	($0.0)	($0.1)	($0.4)	($0.3)	$4.2	562	112
7	Conastone - Peach Bottom	Line	500	$16.2	$14.4	$1.3	$3.1	($0.2)	($0.0)	($1.0)	($1.2)	$1.9	4,814	1,398
8	Bagley - Raphaerd	Line	BGE	$7.2	$5.8	$0.5	$1.9	($0.0)	($0.1)	($0.2)	($0.1)	$1.8	1,208	462
9	Brambleton - Loudoun	Line	Dominion	$3.8	$2.4	$0.1	$1.5	$0.0	($0.1)	$0.0	$0.1	$1.6	760	62
10	Loudoun	Transformer	Dominion	$4.7	$3.3	$0.1	$1.6	($0.0)	($0.2)	($0.2)	($0.0)	$1.6	800	138
11	Conastone - Otter Creek	Line	PPL	$7.5	$6.0	$0.5	$2.0	($0.2)	($0.2)	($0.4)	($0.5)	$1.5	618	316
12	BCPEP	Interface	Pepco	$5.5	$4.4	$0.3	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	820	0
13	Bedington - Black Oak	Interface	500	$7.3	$6.0	$0.2	$1.4	($0.0)	($0.1)	($0.1)	($0.0)	$1.4	3,030	210
14	Person - Halifax	Flowgate	MISO	$7.3	$5.9	$0.0	$1.4	$0.0	($0.0)	($0.0)	$0.0	$1.4	1,438	10
15	Green Street - Westport	Line	BGE	$1.5	$0.3	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	72	0
16	Conastone - Graceton	Line	BGE	$5.5	$4.4	$0.3	$1.3	($0.0)	($0.0)	($0.2)	($0.3)	$1.0	1,230	398
21	Glenarm - Windy Edge	Line	BGE	$1.9	$1.5	$0.1	$0.5	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	794	98
23	Graceton - Safe Harbor	Line	BGE	$2.0	$1.6	$0.2	$0.6	($0.0)	($0.1)	($0.3)	($0.2)	$0.4	1,180	262
25	Brandon Shores - Waugh Chapel	Line	BGE	$0.5	$0.1	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	196	64
26	Five Forks - Graceton	Line	BGE	$1.0	$0.7	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	260	6

DPL Control Zone

Table G-7 DPL Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Loretto - Vienna	Line	DPL	$8.8	$2.3	$1.1	$7.7	($0.4)	$0.1	($0.2)	($0.7)	$7.0	7,900	120
2	Conastone - Peach Bottom	Line	500	($12.8)	($6.5)	($0.7)	($7.0)	$0.5	$0.0	$0.6	$1.1	($5.9)	6,318	1,680
3	Kent - Vaughn	Line	DPL	$4.4	$1.2	$0.4	$3.6	($0.4)	($1.2)	($0.8)	($0.0)	$3.6	1,688	114
4	5004/5005 Interface	Interface	500	$5.6	$2.1	$0.1	$3.6	$0.3	$0.3	($0.1)	($0.1)	$3.5	346	208
5	Graceton - Safe Harbor	Line	BGE	($6.8)	($3.5)	($0.3)	($3.6)	$0.4	$0.3	$0.3	$0.4	($3.2)	6,236	2,302
6	Cedar Creek - Red Lion	Line	DPL	$4.4	$1.3	$0.5	$3.6	($0.3)	($0.0)	($0.9)	($1.2)	$2.4	1,420	68
7	Kenney - Stockton	Line	DPL	$5.2	$15.5	($1.5)	($11.8)	($0.7)	($9.4)	$0.9	$9.6	($2.2)	654	694
8	Conastone - Northwest	Line	BGE	($3.8)	($1.4)	($0.2)	($2.7)	$0.1	($0.1)	$0.3	$0.5	($2.1)	1,950	456
9	Conastone - Otter Creek	Line	PPL	($5.0)	($2.6)	($0.2)	($2.6)	$0.4	$0.2	$0.3	$0.5	($2.1)	2,672	1,736
10	Piney Grove	Transformer	DPL	$9.0	$9.3	($0.0)	($0.4)	($2.4)	($4.8)	$0.0	$2.4	$2.0	704	656
11	Emilie - Falls	Line	PECO	($5.0)	($2.8)	($0.3)	($2.4)	$0.1	$0.0	$0.3	$0.4	($2.0)	10,342	1,790
12	Three Mile Island	Transformer	500	($3.8)	($2.3)	($0.3)	($1.7)	$0.1	$0.0	$0.2	$0.3	($1.5)	1,080	172
13	Edge Moor - Harmony	Line	DPL	$2.2	$0.9	$0.2	$1.5	($0.7)	($0.1)	($2.3)	($2.9)	($1.4)	152	98
14	Butler - Shanor Manor	Line	APS	($3.3)	($1.8)	($0.1)	($1.6)	$0.2	($0.0)	$0.0	$0.2	($1.3)	3,768	530
15	Cedar Creek - Clayton	Line	DPL	$1.6	$0.4	$0.1	$1.3	$0.0	($0.0)	($0.0)	($0.0)	$1.3	670	10
16	Chapelst - Harmony	Line	DPL	$1.2	$0.2	($0.0)	$1.0	($0.0)	($0.0)	($0.0)	$0.0	$1.0	1,162	8
17	Church - New Meredith	Line	DPL	$1.2	$0.4	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	1,236	0
19	Stockton - Kenney	Line	DPL	$0.9	$1.6	($0.2)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	128	0
20	Keeney - Steele	Line	DPL	$0.8	$0.1	$0.1	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	396	8
21	Preston - Tanyard	Line	DPL	$0.8	$0.2	$0.1	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	1,112	2

Table G-8 DPL Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Milford - Steele	Line	DPL	$28.8	$12.0	$1.8	$18.6	$2.1	$1.1	($3.1)	($2.1)	$16.5	3,028	530
2	Conastone - Northwest	Line	BGE	($30.7)	($16.2)	($1.2)	($15.6)	$0.8	$0.7	$1.3	$1.4	($14.2)	5,552	3,680
3	Coolspring - Milford	Line	DPL	$16.8	$4.3	$0.2	$12.6	($0.8)	($1.7)	($0.0)	$0.8	$13.4	1,124	90
4	Graceton	Transformer	BGE	($20.3)	($10.7)	($1.0)	($10.6)	$0.5	$0.3	$0.8	$0.9	($9.6)	6,234	2,596
5	Bagley - Graceton	Line	BGE	($20.3)	($10.3)	($0.9)	($10.8)	$1.0	$0.4	$0.8	$1.4	($9.4)	6,626	3,370
6	Stockton - Kenney	Line	DPL	$7.7	$13.9	($0.8)	($7.0)	$0.0	$0.0	$0.0	$0.0	($7.0)	1,470	0
7	Mardela - Vienna	Line	DPL	$6.6	$4.2	$0.5	$2.9	($0.8)	($4.4)	($0.5)	$3.1	$6.0	4,734	760
8	Kenney - Stockton	Line	DPL	$0.4	$0.3	$0.0	$0.0	($1.2)	($7.5)	($0.5)	$5.8	$5.9	66	1,518
9	Worcester - Ocean Pines	Line	DPL	$0.0	$0.0	$0.0	$0.0	($3.9)	$0.3	($0.5)	($4.7)	($4.7)	0	270
10	Church - New Meredith	Line	DPL	$7.3	$3.7	$0.6	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	3,468	0
11	Loretto - Vienna	Line	DPL	$3.6	$0.5	$1.1	$4.1	($0.0)	$0.0	($0.0)	($0.0)	$4.1	3,734	12
12	Conastone - Peach Bottom	Line	500	($9.2)	($5.5)	($0.6)	($4.2)	$0.3	$0.4	$0.6	$0.5	($3.7)	4,814	1,398
13	Worcrester - Ocean Pines	Line	DPL	$3.1	$0.5	$0.2	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,012	0
14	Bagley - Raphaerd	Line	BGE	($2.3)	($0.7)	($0.1)	($1.7)	$0.0	$0.0	$0.1	$0.1	($1.6)	1,208	462
15	Preston - Tanyard	Line	DPL	$1.5	$0.3	$0.2	$1.4	($0.0)	($0.0)	($0.0)	($0.1)	$1.3	1,706	20
16	Cedar Creek - Red Lion	Line	DPL	$1.7	$0.5	$0.2	$1.4	$0.0	$0.1	($0.1)	($0.1)	$1.2	504	14
17	New Meredith - Church	Line	DPL	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.2)	($0.6)	($1.0)	($1.0)	0	564
19	Vienna - Mardela	Line	DPL	$2.7	$3.5	($0.1)	($0.9)	$0.0	$0.0	$0.0	$0.0	($0.9)	308	0
22	Chapelst - Harmony	Line	DPL	$0.8	$0.1	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	1,388	0
23	Cartanza - Redlion	Line	DPL	$0.5	$0.1	$0.3	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	270	0

JCPL Control Zone

Table G-9 JCPL Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	5004/5005 Interface	Interface	500	$6.0	$2.7	$0.1	$3.3	$0.2	$0.2	($0.2)	($0.1)	$3.2	346	208
2	Emilie - Falls	Line	PECO	$8.0	$6.3	$0.5	$2.2	$0.3	($0.1)	($0.4)	$0.0	$2.2	10,342	1,790
3	Kilmer - Sayreville	Line	PSEG	($0.9)	($2.9)	($0.1)	$1.9	($0.0)	$0.4	$0.2	($0.1)	$1.8	2,342	480
4	Graceton - Safe Harbor	Line	BGE	($9.5)	($8.1)	($0.1)	($1.5)	$0.5	$0.6	$0.2	$0.1	($1.3)	6,236	2,302
5	Cedar Grove - Clifton	Line	PSEG	($2.3)	($1.1)	($0.3)	($1.4)	$0.0	$0.1	$0.2	$0.1	($1.3)	2,358	158
6	Conastone - Northwest	Line	BGE	($4.2)	($3.5)	($0.1)	($0.7)	$0.2	$0.3	$0.1	($0.0)	($0.8)	1,950	456
7	North Meshoppen - Oxbow	Line	PENELEC	$1.0	$0.6	($0.1)	$0.4	$0.0	($0.0)	$0.1	$0.1	$0.5	2,196	356
8	Conastone - Otter Creek	Line	PPL	($6.7)	($6.3)	($0.1)	($0.5)	$0.4	$0.5	$0.1	$0.0	($0.5)	2,672	1,736
9	Brunner Island - Yorkanna	Line	Met-Ed	($2.4)	($2.0)	($0.1)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	1,362	148
10	Butler - Shanor Manor	Line	APS	($4.3)	($3.9)	($0.0)	($0.5)	$0.1	$0.1	$0.0	$0.0	($0.4)	3,768	530
11	Carson - Rawlings	Line	Dominion	$0.9	$0.6	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	1,440	462
12	Person - Sedge Hill	Line	Dominion	$0.9	$0.6	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.1)	$0.3	2,498	420
13	Cedar Grove Sub - Roseland	Line	PSEG	($0.8)	($0.4)	($0.1)	($0.4)	$0.1	$0.1	$0.2	$0.1	($0.3)	710	108
14	Lakeview - Greenfield	Line	ATSI	$1.2	$0.9	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	3,186	328
15	Lakewood - Larrabee	Line	JCPL	($0.1)	($0.3)	($0.0)	$0.3	$0.0	$0.0	($0.0)	$0.0	$0.3	152	10
23	Pequest River - Portland	Line	JCPL	($0.0)	$0.1	($0.0)	($0.1)	($0.1)	($0.1)	$0.0	($0.1)	($0.1)	152	188
28	Gilbert	Other	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	22
48	Stoneybrook - Whippany	Line	JCPL	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	316	0
55	Whippany	Other	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	22
62	Sayreville - Sayreville	Line	JCPL	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	1,350	0

Table G-10 JCPL Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Graceton	Transformer	BGE	($21.9)	($17.7)	($0.3)	($4.4)	$0.1	($0.0)	$0.2	$0.4	($4.1)	6,234	2,596
2	Conastone - Northwest	Line	BGE	($34.7)	($30.9)	($0.3)	($4.2)	$1.3	$1.5	$0.3	$0.1	($4.1)	5,552	3,680
3	Bagley - Graceton	Line	BGE	($22.4)	($20.0)	($0.3)	($2.7)	$0.7	$0.5	$0.2	$0.4	($2.2)	6,626	3,370
4	Kilmer - Sayreville	Line	PSEG	($0.8)	($2.8)	($0.2)	$1.8	$0.0	$0.2	$0.0	($0.1)	$1.7	2,316	814
5	Conastone - Otter Creek	Line	PPL	($3.1)	($2.1)	($0.0)	($1.0)	$0.2	$0.2	$0.0	$0.1	($1.0)	618	316
6	Cedar Grove Sub - Roseland	Line	PSEG	($1.3)	($0.8)	($0.4)	($0.9)	($0.0)	$0.0	$0.0	($0.0)	($1.0)	2,006	46
7	Bagley - Raphaerd	Line	BGE	($2.4)	($1.9)	($0.0)	($0.6)	($0.0)	$0.0	$0.0	($0.0)	($0.6)	1,208	462
8	Emilie - Falls	Line	PECO	$1.9	$1.5	$0.1	$0.5	$0.1	($0.0)	($0.1)	$0.0	$0.5	5,234	658
9	Person - Halifax	Flowgate	MISO	$1.3	$0.9	$0.0	$0.5	$0.0	($0.0)	($0.0)	($0.0)	$0.5	1,438	10
10	Brambleton - Loudoun	Line	Dominion	$1.8	$1.4	$0.0	$0.4	$0.1	$0.0	($0.0)	$0.0	$0.5	760	62
11	Hawthorne - Hinchmans Ave	Line	PSEG	$0.8	$0.4	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	130	0
12	Plymouth Meeting - Whitpain	Line	PECO	($1.0)	($0.7)	($0.2)	($0.5)	$0.0	$0.0	$0.1	$0.2	($0.3)	770	58
13	Loudoun	Transformer	Dominion	$1.1	$0.9	$0.0	$0.3	$0.1	($0.0)	($0.1)	$0.0	$0.3	800	138
14	Cedar Grove - Clifton	Line	PSEG	($0.5)	($0.3)	($0.1)	($0.3)	($0.0)	$0.0	$0.1	$0.0	($0.3)	924	48
15	West	Interface	500	$0.9	$0.7	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.3	330	4
29	Sayreville - Sayreville	Line	JCPL	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	3,770	0
34	Atlantic - Red Bank	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.1	$0.1	0	6
137	Franklin - Vernon	Line	JCPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4,136	0
146	Red Oak - Sayreville	Line	JCPL	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	452	0
213	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	74	0

Met-Ed Control Zone

Table G-11 Met-Ed Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Gardners - Texas East	Line	Met-Ed	$2.1	($1.0)	$0.2	$3.3	($0.6)	($0.4)	($0.4)	($0.6)	$2.7	2,634	232
2	Brunner Island - Yorkanna	Line	Met-Ed	$0.6	($1.8)	($0.0)	$2.3	$0.0	($0.1)	($0.0)	$0.0	$2.4	1,362	148
3	Middletown Jct - Brunner Island	Line	PPL	($0.3)	($2.3)	($0.1)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	1,186	0
4	Graceton - Safe Harbor	Line	BGE	($10.8)	($12.7)	($0.6)	$1.3	$0.3	$0.7	$0.9	$0.5	$1.8	6,236	2,302
5	Saxton - Three Springs	Line	PENELEC	$3.4	$1.8	$0.3	$1.9	$0.1	$0.1	($0.3)	($0.3)	$1.5	1,776	302
6	Middletown Jct	Transformer	Met-Ed	$1.1	($0.1)	$0.2	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	2,068	0
7	Carlisle Pike - Roxbury	Line	PENELEC	$2.7	$1.1	$0.0	$1.6	($0.3)	($0.2)	($0.2)	($0.3)	$1.4	796	232
8	Jackson - Three Mile Island	Line	Met-Ed	$0.6	($0.6)	$0.1	$1.3	($0.0)	$0.0	$0.0	$0.0	$1.3	772	56
9	Conastone - Otter Creek	Line	PPL	($8.5)	($7.5)	($0.9)	($2.0)	$0.3	$0.8	$1.3	$0.8	($1.2)	2,672	1,736
10	Conastone - Northwest	Line	BGE	($3.3)	($4.6)	($0.2)	$1.2	$0.0	$0.2	$0.2	($0.1)	$1.1	1,950	456
11	Middletown Jct	Other	Met-Ed	$0.9	($0.1)	$0.3	$1.3	$0.0	$0.1	($0.1)	($0.2)	$1.1	1,890	144
12	Butler - Shanor Manor	Line	APS	($3.1)	($4.1)	($0.1)	$0.9	$0.1	$0.1	$0.1	$0.1	$1.0	3,768	530
13	Pequest River - Portland	Line	JCPL	$1.1	$0.8	$0.0	$0.3	($1.1)	$0.0	($0.1)	($1.1)	($0.8)	152	188
14	Roxana - Praxair	Flowgate	MISO	$1.1	$1.9	$0.0	($0.8)	$0.0	($0.1)	($0.0)	$0.0	($0.8)	3,468	580
15	Three Mile Island	Transformer	500	$3.9	$3.5	$0.3	$0.7	$0.2	$0.1	($0.2)	($0.0)	$0.7	1,080	172
17	Newberry - Round Top	Line	Met-Ed	$0.7	$0.1	$0.1	$0.7	($0.0)	($0.0)	($0.0)	($0.1)	$0.6	948	64
18	Gardners - Texas Eastern	Line	Met-Ed	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	124	0
31	Hunterstown	Transformer	Met-Ed	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	238	0
36	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.2)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	310	0
38	Hummelstown - Middletown Jct	Line	Met-Ed	$0.0	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	104	0

Table G-12 Met-Ed Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	($27.7)	($41.4)	($1.5)	$12.2	$0.4	$1.9	$1.6	$0.1	$12.3	5,552	3,680
2	Bagley - Graceton	Line	BGE	($17.9)	($27.1)	($1.0)	$8.2	$0.4	$1.4	$0.8	($0.2)	$8.0	6,626	3,370
3	Jackson - Three Mile Island	Line	Met-Ed	$4.0	($0.8)	$0.2	$5.0	$0.0	$0.1	($0.1)	($0.3)	$4.7	870	40
4	Graceton	Transformer	BGE	($14.6)	($20.0)	($0.5)	$4.9	($0.1)	$0.5	$0.4	($0.2)	$4.7	6,234	2,596
5	Jackson - North Hanover	Line	Met-Ed	$3.8	$1.3	$0.4	$2.8	($0.2)	$0.3	($0.6)	($1.1)	$1.7	1,790	110
6	Conastone - Peach Bottom	Line	500	($3.7)	($4.7)	$0.4	$1.4	$0.1	$0.1	($0.1)	($0.2)	$1.2	4,814	1,398
7	Hunterstown	Transformer	Met-Ed	$1.3	$0.3	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	942	32
8	Gardners - Texas East	Line	Met-Ed	$0.4	($0.5)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	1,972	0
9	Middletown Jct	Other	Met-Ed	$1.3	$0.0	$0.2	$1.4	$0.1	$0.1	($0.8)	($0.7)	$0.7	1,236	98
10	Conastone - Graceton	Line	BGE	($1.2)	($1.9)	($0.1)	$0.6	$0.0	$0.1	$0.0	$0.0	$0.6	1,230	398
11	Middletown Jct	Transformer	Met-Ed	$0.5	$0.0	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	908	0
12	Brunner Island - Yorkanna	Line	Met-Ed	$0.2	($0.4)	$0.1	$0.7	$0.0	$0.0	($0.2)	($0.1)	$0.5	474	52
13	Three Mile Island	Transformer	500	$0.8	$0.7	$0.3	$0.4	$0.1	($0.0)	($0.1)	($0.0)	$0.4	596	94
14	Bagley - Raphaerd	Line	BGE	($1.9)	($2.4)	($0.1)	$0.4	($0.0)	$0.1	$0.1	($0.0)	$0.3	1,208	462
15	Loudoun	Transformer	Dominion	$0.9	$1.3	$0.0	($0.3)	$0.1	($0.0)	($0.1)	$0.0	($0.3)	800	138
18	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	$0.0	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	2,516	0
19	Newberry - Round Top	Line	Met-Ed	$0.4	$0.1	$0.0	$0.3	$0.0	$0.1	($0.0)	($0.1)	$0.3	186	30
22	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	196	0
44	Smith Jct - Smith St.	Line	Met-Ed	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	198	0
63	Germantown - Straban	Line	Met-Ed	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	126	0

PECO Control Zone

Table G-13 PECO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	($26.6)	($48.3)	($0.9)	$20.8	$1.3	$0.7	$0.9	$1.5	$22.3	6,318	1,680
2	Graceton - Safe Harbor	Line	BGE	($15.7)	($25.6)	($0.2)	$9.7	$0.9	$0.7	$0.3	$0.6	$10.2	6,236	2,302
3	Conastone - Otter Creek	Line	PPL	($12.1)	($18.8)	($0.3)	$6.4	$0.6	$0.4	$0.4	$0.6	$6.9	2,672	1,736
4	Three Mile Island	Transformer	500	($7.7)	($13.8)	($0.3)	$5.8	($0.2)	($0.0)	$0.4	$0.2	$6.0	1,080	172
5	Emilie - Falls	Line	PECO	($15.2)	($21.5)	($1.0)	$5.3	($0.7)	$0.4	$1.0	($0.1)	$5.2	10,342	1,790
6	Conastone - Northwest	Line	BGE	($8.4)	($13.8)	($0.2)	$5.1	$0.3	$0.4	$0.2	$0.1	$5.2	1,950	456
7	Butler - Shanor Manor	Line	APS	($7.7)	($11.2)	($0.1)	$3.5	$0.2	$0.0	$0.0	$0.3	$3.8	3,768	530
8	5004/5005 Interface	Interface	500	$11.3	$12.7	$0.1	($1.4)	$0.9	$2.2	($0.2)	($1.5)	($2.9)	346	208
9	Nottingham	Other	PECO	($3.8)	($6.6)	($0.2)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	2,130	0
10	Brunner Island - Yorkanna	Line	Met-Ed	($4.1)	($6.3)	($0.2)	$2.1	$0.0	$0.0	$0.1	$0.1	$2.1	1,362	148
11	Plymouth Meeting - Whitpain	Line	PECO	$2.0	$0.4	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	188	0
12	Bagley - Graceton	Line	BGE	($3.0)	($4.8)	($0.1)	$1.6	$0.2	$0.1	$0.1	$0.2	$1.8	1,108	254
13	Peachbottom	Transformer	PECO	$0.7	($0.8)	($0.0)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	178	0
14	Middletown Jct - Brunner Island	Line	PPL	($2.0)	($3.4)	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1,186	0
15	Limerick	Transformer	500	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	134	0
20	Chichester - Eddystone	Line	PECO	$0.9	($0.1)	$0.2	$1.2	$0.3	$0.1	($0.4)	($0.2)	$1.0	630	64
22	Chichester - Foulke	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.3	($0.6)	($0.9)	($0.9)	0	326
24	Foulk - Chichester	Line	PECO	$0.5	($0.2)	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	368	0
30	Phillips Island	Transformer	PECO	($0.0)	($0.6)	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	3,352	0
32	Cromby - Limerick	Line	PECO	$0.8	$0.1	$0.0	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	824	26

Table G-14 PECO Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	($70.6)	($114.3)	($1.3)	$42.4	$2.1	$1.8	$1.4	$1.7	$44.1	5,552	3,680
2	Bagley - Graceton	Line	BGE	($46.5)	($72.6)	($1.6)	$24.5	$2.0	$1.2	$1.6	$2.4	$26.8	6,626	3,370
3	Graceton	Transformer	BGE	($44.1)	($60.8)	($2.4)	$14.3	$0.7	$0.8	$2.2	$2.1	$16.4	6,234	2,596
4	Conastone - Peach Bottom	Line	500	($19.7)	($36.4)	($0.6)	$16.1	$0.7	$1.0	$0.4	$0.1	$16.2	4,814	1,398
5	Plymouth Meeting - Whitpain	Line	PECO	$12.3	$4.0	$0.6	$8.9	($0.3)	$0.1	($0.3)	($0.8)	$8.1	770	58
6	Conastone - Otter Creek	Line	PPL	($5.3)	($9.1)	$0.0	$3.7	$0.3	$0.3	($0.1)	($0.1)	$3.7	618	316
7	Bagley - Raphaerd	Line	BGE	($5.0)	($7.7)	($0.1)	$2.6	$0.0	$0.0	$0.1	$0.1	$2.7	1,208	462
8	Emilie - Falls	Line	PECO	($5.6)	($8.3)	($0.1)	$2.5	($0.2)	($0.1)	$0.3	$0.2	$2.7	5,234	658
9	Conastone - Graceton	Line	BGE	($3.1)	($5.4)	($0.1)	$2.3	$0.2	$0.1	$0.1	$0.2	$2.5	1,230	398
10	Emilie	Transformer	PECO	($0.2)	($2.0)	$0.2	$1.9	($0.0)	($0.1)	($0.1)	$0.1	$2.0	1,328	220
11	Passyunk - Schuylkill	Line	PECO	$1.5	$0.0	$0.0	$1.5	($0.1)	($0.0)	($0.0)	($0.1)	$1.4	268	134
12	Three Mile Island	Transformer	500	($1.5)	($2.8)	($0.0)	$1.3	$0.0	$0.0	$0.1	$0.1	$1.3	596	94
13	Person - Halifax	Flowgate	MISO	$2.6	$4.0	$0.1	($1.3)	$0.0	($0.0)	($0.0)	$0.0	($1.3)	1,438	10
14	Butler - Shanor Manor	Line	APS	($2.6)	($3.7)	($0.0)	$1.1	$0.2	$0.1	$0.0	$0.1	$1.2	1,068	168
15	Loudoun	Transformer	Dominion	$2.4	$3.5	$0.1	($1.1)	$0.0	$0.1	($0.1)	($0.2)	($1.2)	800	138
16	Chichester - Eddystone	Line	PECO	$0.8	($0.1)	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	628	0
23	Richmond - Waneeta	Line	PECO	$0.6	($0.3)	$0.2	$1.1	($0.0)	$0.3	($0.0)	($0.3)	$0.7	624	176
25	Cromby - Limerick	Line	PECO	$1.1	$0.2	$0.0	$0.9	($0.2)	$0.1	($0.1)	($0.4)	$0.6	758	344
27	Chichester - Linwood	Line	PECO	$0.7	($0.3)	$0.0	$1.0	($0.0)	$0.2	($0.2)	($0.5)	$0.5	328	6
29	Cromby - Moser	Line	PECO	$0.5	$0.0	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.5	406	0

PENELEC Control Zone

Table G-15 PENELEC Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	5004/5005 Interface	Interface	500	($10.8)	($18.9)	($2.0)	$6.0	$0.7	$2.2	$3.5	$2.0	$8.0	346	208
2	Butler - Shanor Manor	Line	APS	($14.4)	($22.6)	($0.4)	$7.9	$0.2	$1.2	$0.3	($0.8)	$7.1	3,768	530
3	East Townada - North Meshoppen	Line	PENELEC	($3.1)	($8.1)	($0.6)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	3,604	0
4	Graceton - Safe Harbor	Line	BGE	($7.9)	($11.1)	$0.1	$3.2	$0.2	$0.6	($0.0)	($0.4)	$2.8	6,236	2,302
5	Conastone - Peach Bottom	Line	500	($5.6)	($8.4)	$0.3	$3.1	$0.1	$0.3	($0.2)	($0.5)	$2.7	6,318	1,680
6	Saxton - Three Springs	Line	PENELEC	($9.6)	($13.3)	($0.7)	$3.0	($0.7)	$1.0	$1.1	($0.5)	$2.5	1,776	302
7	Conastone - Northwest	Line	BGE	($5.3)	($7.8)	($0.0)	$2.4	$0.1	$0.3	$0.1	($0.1)	$2.3	1,950	456
8	East Towanda - Hillside	Line	PENELEC	($1.3)	($3.7)	($0.3)	$2.1	$0.0	$0.0	$0.1	$0.1	$2.1	1,876	354
9	AP South	Interface	500	($6.4)	($8.4)	($0.1)	$1.9	$0.1	$0.2	$0.0	($0.1)	$1.9	2,630	148
10	Gardners - Texas East	Line	Met-Ed	$5.1	$3.7	$0.3	$1.7	$0.0	($0.6)	($0.4)	$0.1	$1.9	2,634	232
11	North Meshoppen - Oxbow	Line	PENELEC	($7.0)	($9.8)	($1.0)	$1.7	$0.4	$1.2	$0.8	$0.0	$1.8	2,196	356
12	Lakeview - Greenfield	Line	ATSI	$7.4	$9.2	$0.4	($1.4)	($0.1)	($0.4)	($0.3)	($0.1)	($1.5)	3,186	328
13	Roxana - Praxair	Flowgate	MISO	$4.9	$6.5	$0.1	($1.5)	($0.0)	($0.2)	($0.1)	$0.2	($1.4)	3,468	580
14	Conemaugh	Transformer	PENELEC	$2.4	$1.0	$0.1	$1.5	$0.0	$0.0	($0.1)	($0.1)	$1.3	240	82
15	East Sayre - East Towanda	Line	PENELEC	($0.7)	($2.9)	($0.3)	$1.8	$0.0	$1.0	$0.4	($0.6)	$1.2	1,642	522
18	SENECA	Interface	PENELEC	$0.2	$0.9	($0.0)	($0.7)	($0.1)	($0.0)	($0.3)	($0.4)	($1.1)	228	310
22	Asylum	Transformer	PENELEC	($0.0)	($0.9)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	1,718	0
24	Grandview - Titusville	Line	PENELEC	($1.9)	($2.9)	($0.1)	$0.9	$0.1	$0.2	$0.1	($0.0)	$0.8	440	40
25	Hillclay Junction - Hilltop	Line	PENELEC	$0.5	$0.4	$0.0	$0.1	($0.1)	($0.5)	($1.3)	($0.9)	($0.8)	28	24
29	Seneca	Transformer	PENELEC	$0.0	($0.3)	$0.4	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	6,798	0

Table G-16 PENELEC Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	($36.4)	($46.6)	$0.2	$10.4	$0.3	$2.2	($0.2)	($2.1)	$8.4	5,552	3,680
2	Graceton	Transformer	BGE	($21.3)	($29.3)	$0.3	$8.4	$0.4	$0.8	($0.2)	($0.6)	$7.8	6,234	2,596
3	Bagley - Graceton	Line	BGE	($23.2)	($30.3)	$0.4	$7.5	$0.3	$1.2	($0.4)	($1.3)	$6.2	6,626	3,370
4	Butler - Shanor Manor	Line	APS	($5.1)	($7.5)	($0.1)	$2.3	$0.4	$1.1	$0.2	($0.5)	$1.8	1,068	168
5	Bagley - Raphaerd	Line	BGE	($3.1)	($4.5)	$0.1	$1.4	$0.0	$0.0	($0.0)	($0.0)	$1.4	1,208	462
6	Bedington - Black Oak	Interface	500	($4.6)	($6.0)	($0.0)	$1.4	$0.1	$0.1	($0.0)	($0.0)	$1.3	3,030	210
7	Mainesburg - Mansfield	Line	PENELEC	$1.7	$0.5	$0.7	$1.9	($1.2)	($0.0)	($2.0)	($3.1)	($1.2)	4,196	282
8	AP South	Interface	500	($3.7)	($4.8)	$0.0	$1.2	$0.0	$0.0	$0.0	($0.0)	$1.2	2,152	28
9	Person - Halifax	Flowgate	MISO	$1.2	$2.1	$0.2	($0.8)	($0.0)	$0.0	($0.0)	($0.0)	($0.8)	1,438	10
10	Butler - Karns City	Line	APS	$4.5	$3.9	$0.1	$0.7	($0.1)	($0.1)	($0.0)	($0.0)	$0.7	886	20
11	Brambleton - Loudoun	Line	Dominion	$2.1	$2.8	$0.0	($0.7)	($0.0)	($0.1)	($0.0)	$0.0	($0.7)	760	62
12	Roxana - Praxair	Flowgate	MISO	$2.2	$2.9	$0.1	($0.6)	($0.0)	($0.1)	($0.1)	($0.1)	($0.7)	1,768	896
13	Plymouth Meeting - Whitpain	Line	PECO	($2.2)	($2.9)	($0.0)	$0.7	$0.1	$0.1	$0.0	($0.0)	$0.7	770	58
14	Milford - Steele	Line	DPL	($1.9)	($2.6)	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	3,028	530
15	Everts Drive - South Troy	Line	PENELEC	($1.8)	($2.6)	$0.1	$0.9	($0.1)	$0.0	($0.2)	($0.3)	$0.6	3,934	154
16	Warren	Interface	PENELEC	$0.3	$0.2	$0.0	$0.0	($0.5)	$0.1	($0.0)	($0.6)	($0.6)	70	56
21	North Meshoppen - Oxbow	Line	PENELEC	($1.2)	($1.9)	($0.2)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	560	92
22	East Townada - North Meshoppen	Line	PENELEC	($0.6)	($1.2)	($0.1)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	454	0
23	East Sayre - East Towanda	Line	PENELEC	($0.0)	($0.5)	($0.1)	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	216	0
24	31st Street - Westfall	Line	PENELEC	($1.2)	($1.6)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	92	0

Pepco Control Zone

Table G-17 Pepco Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	$28.3	$21.4	$0.4	$7.2	($0.8)	($1.2)	($0.2)	$0.2	$7.4	6,318	1,680
2	Graceton - Safe Harbor	Line	BGE	$28.2	$21.6	$0.6	$7.2	($0.4)	($0.9)	($0.6)	($0.1)	$7.0	6,236	2,302
3	Conastone - Otter Creek	Line	PPL	$17.0	$13.1	$0.3	$4.2	($0.2)	($0.8)	($0.3)	$0.2	$4.4	2,672	1,736
4	Conastone - Northwest	Line	BGE	$14.5	$11.0	$0.2	$3.7	($0.1)	($0.5)	($0.1)	$0.4	$4.0	1,950	456
5	AP South	Interface	500	$13.1	$10.8	$0.2	$2.5	$0.0	($0.0)	($0.1)	($0.0)	$2.4	2,630	148
6	Pleasant View - Ashburn	Line	Dominion	($5.1)	($3.8)	($0.0)	($1.4)	($0.0)	$0.2	($0.1)	($0.3)	($1.7)	946	170
7	Person - Sedge Hill	Line	Dominion	$7.2	$5.9	$0.1	$1.5	$0.0	($0.3)	($0.1)	$0.1	$1.6	2,498	420
8	Carson - Rawlings	Line	Dominion	$7.6	$6.2	$0.1	$1.4	$0.0	($0.2)	($0.1)	$0.2	$1.6	1,440	462
9	Bedington - Black Oak	Interface	500	$6.9	$5.5	$0.1	$1.5	($0.0)	($0.0)	($0.0)	$0.0	$1.5	2,430	122
10	Brunner Island - Yorkanna	Line	Met-Ed	$5.3	$4.1	$0.1	$1.3	$0.0	($0.1)	($0.0)	$0.0	$1.3	1,362	148
11	BCPEP	Interface	Pepco	$4.6	$3.3	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,114	0
12	Bagley - Graceton	Line	BGE	$4.7	$3.6	$0.0	$1.2	($0.0)	($0.1)	($0.0)	$0.0	$1.2	1,108	254
13	Roxana - Praxair	Flowgate	MISO	$5.1	$3.9	$0.1	$1.2	($0.0)	($0.1)	($0.1)	($0.0)	$1.2	3,468	580
14	Three Mile Island	Transformer	500	$5.4	$4.5	$0.1	$1.1	($0.2)	($0.2)	($0.1)	($0.0)	$1.0	1,080	172
15	Nottingham	Other	PECO	$3.3	$2.5	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	2,130	0
36	Bethesda - O St.	Line	Pepco	$0.9	$0.8	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	146	0
51	Burches Hill - Talbert	Line	Pepco	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	24
71	Chalk Point	Transformer	Pepco	$0.1	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.1	206	32
76	Butler - Cabot	Line	Pepco	($0.2)	($0.2)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	68	0
80	Howard - Pumphrey	Line	Pepco	($0.2)	($0.1)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	318	0

Table G-18 Pepco Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	$119.2	$93.7	$2.1	$27.6	$0.5	($3.8)	($2.3)	$2.1	$29.7	5,552	3,680
2	Bagley - Graceton	Line	BGE	$73.4	$56.8	$1.2	$17.9	$0.2	($2.0)	($1.2)	$1.0	$18.9	6,626	3,370
3	Graceton	Transformer	BGE	$62.3	$48.3	$0.9	$14.8	$0.1	($1.1)	($0.5)	$0.7	$15.5	6,234	2,596
4	Conastone - Peach Bottom	Line	500	$22.1	$17.8	$0.6	$4.9	$0.1	($0.5)	($0.5)	$0.1	$5.0	4,814	1,398
5	Bedington - Black Oak	Interface	500	$11.3	$8.7	$0.2	$2.8	($0.0)	($0.1)	($0.1)	($0.0)	$2.8	3,030	210
6	Person - Halifax	Flowgate	MISO	$10.2	$7.7	$0.2	$2.7	($0.0)	($0.0)	($0.0)	($0.0)	$2.7	1,438	10
7	AP South	Interface	500	$9.4	$6.8	$0.2	$2.7	($0.0)	($0.0)	($0.0)	($0.0)	$2.7	2,152	28
8	Bagley - Raphaerd	Line	BGE	$8.0	$5.9	$0.2	$2.2	($0.1)	($0.1)	($0.1)	$0.0	$2.2	1,208	462
9	BCPEP	Interface	Pepco	$8.2	$6.3	$0.2	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	820	0
10	Conastone - Otter Creek	Line	PPL	$10.3	$8.6	$0.3	$2.0	$0.0	($0.2)	($0.3)	($0.1)	$1.9	618	316
11	Loudoun	Transformer	Dominion	$6.9	$5.3	$0.1	$1.7	($0.1)	($0.3)	($0.2)	$0.0	$1.7	800	138
12	Brambleton - Loudoun	Line	Dominion	$5.7	$4.5	$0.2	$1.3	$0.0	($0.1)	($0.1)	$0.1	$1.4	760	62
13	Conastone - Graceton	Line	BGE	$5.4	$4.4	$0.1	$1.1	$0.0	($0.2)	($0.1)	$0.1	$1.2	1,230	398
14	Graceton - Safe Harbor	Line	BGE	$2.2	$1.7	$0.1	$0.6	$0.0	($0.1)	($0.1)	$0.1	$0.7	1,180	262
15	Roxana - Praxair	Flowgate	MISO	$2.4	$1.8	$0.0	$0.7	$0.0	($0.1)	($0.1)	$0.0	$0.7	1,768	896
19	Fort Slocum - Takoma	Line	Pepco	$1.5	$1.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	144	0
61	Potomac River	Transformer	Pepco	$0.1	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	62	0
81	Howard - Pumphrey	Line	Pepco	($0.2)	($0.1)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	200	0
135	Bowie	Transformer	Pepco	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0
140	12th St - Ft Slocum	Line	Pepco	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	82	0

PPL Control Zone

Table G-19 PPL Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	($16.4)	($24.3)	$0.2	$8.1	$0.4	$0.3	$0.2	$0.3	$8.3	6,318	1,680
2	Quarry - Steel City	Line	PPL	($0.0)	($4.6)	($0.2)	$4.4	$0.0	($0.1)	$0.5	$0.5	$4.9	3,016	600
3	Three Mile Island	Transformer	500	$1.0	($3.5)	$0.0	$4.5	$0.0	($0.2)	$0.1	$0.3	$4.8	1,080	172
4	Conastone - Otter Creek	Line	PPL	($17.8)	($22.6)	($0.7)	$4.0	$0.9	$1.6	$0.9	$0.3	$4.3	2,672	1,736
5	5004/5005 Interface	Interface	500	$14.3	$16.1	$0.2	($1.5)	$0.3	$1.3	($0.5)	($1.4)	($3.0)	346	208
6	Butler - Shanor Manor	Line	APS	($8.3)	($11.2)	($0.1)	$2.8	$0.1	$0.3	$0.1	($0.1)	$2.7	3,768	530
7	Jenkins - Susquehanna	Line	PPL	$0.2	($1.8)	($0.0)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	494	0
8	Brunner Island - Yorkanna	Line	Met-Ed	($4.5)	($6.6)	($0.1)	$1.9	$0.0	$0.1	$0.0	$0.0	$1.9	1,362	148
9	Graceton - Safe Harbor	Line	BGE	($26.9)	($29.0)	($1.2)	$0.8	$1.1	$1.6	$1.5	$1.0	$1.8	6,236	2,302
10	Emilie - Falls	Line	PECO	$3.0	$4.5	($0.2)	($1.7)	($0.0)	($0.1)	$0.3	$0.3	($1.4)	10,342	1,790
11	Middletown Jct - Brunner Island	Line	PPL	$0.1	($1.1)	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,186	0
12	Elimsport - Sunbury	Line	PPL	($0.3)	($1.3)	($0.0)	$0.9	($0.0)	($0.0)	$0.0	$0.1	$1.0	308	186
13	Roxana - Praxair	Flowgate	MISO	$3.0	$3.8	$0.0	($0.9)	($0.0)	($0.0)	($0.0)	($0.0)	($0.9)	3,468	580
14	East Townada - North Meshoppen	Line	PENELEC	$3.2	$4.3	$0.3	($0.9)	$0.0	$0.0	$0.0	$0.0	($0.9)	3,604	0
15	North Meshoppen - Oxbow	Line	PENELEC	$4.6	$5.5	$0.1	($0.8)	$0.0	($0.0)	($0.1)	($0.0)	($0.9)	2,196	356
16	Face Rock	Other	PPL	($3.0)	($4.1)	($0.2)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	1,070	0
17	Harwood - Susquehanna	Line	PPL	$0.3	($0.3)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	46	0
19	Milton - Montour	Line	PPL	($0.1)	($0.5)	($0.0)	$0.5	($0.0)	$0.0	$0.0	$0.0	$0.5	112	60
30	Martins Creek - Quarry	Line	PPL	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	$0.1	$0.0	$0.3	248	100
36	Safe Harbor	Transformer	PPL	($0.0)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,628	0

Table G-20 PPL Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Graceton	Transformer	BGE	($32.5)	($45.2)	($0.3)	$12.4	($0.1)	$2.6	$0.1	($2.6)	$9.7	6,234	2,596
2	Bagley - Graceton	Line	BGE	($46.2)	($51.7)	($0.7)	$4.8	$0.8	$1.1	$0.6	$0.2	$5.0	6,626	3,370
3	Conastone - Peach Bottom	Line	500	($13.4)	($17.5)	($0.0)	$4.0	$0.3	$0.5	$0.0	($0.2)	$3.8	4,814	1,398
4	Conastone - Northwest	Line	BGE	($71.3)	($76.2)	($0.8)	$4.2	$0.9	$2.0	$0.8	($0.4)	$3.8	5,552	3,680
5	Milton - Montour	Line	PPL	($0.2)	($2.7)	($0.0)	$2.5	$0.0	($0.0)	($0.0)	$0.0	$2.5	290	168
6	Jackson - Three Mile Island	Line	Met-Ed	$1.0	($0.6)	($0.0)	$1.6	$0.0	($0.6)	$0.0	$0.6	$2.2	870	40
7	Quarry - Steel City	Line	PPL	$0.1	($1.8)	($0.0)	$1.8	$0.0	$0.1	($0.2)	($0.3)	$1.6	1,244	624
8	Three Mile Island	Transformer	500	$0.2	($0.9)	$0.0	$1.2	$0.0	($0.0)	($0.0)	$0.0	$1.2	596	94
9	Plymouth Meeting - Whitpain	Line	PECO	($2.6)	($3.7)	($0.1)	$1.0	$0.0	$0.0	$0.1	$0.0	$1.1	770	58
10	Brambleton - Loudoun	Line	Dominion	$2.6	$3.2	$0.0	($0.6)	$0.1	($0.0)	($0.0)	$0.1	($0.5)	760	62
11	Butler - Shanor Manor	Line	APS	($2.7)	($3.3)	($0.0)	$0.6	$0.0	$0.2	$0.1	($0.1)	$0.5	1,068	168
12	Bagley - Raphaerd	Line	BGE	($5.3)	($5.8)	($0.1)	$0.5	($0.0)	$0.0	$0.1	($0.0)	$0.4	1,208	462
13	Conastone - Graceton	Line	BGE	($3.1)	($3.6)	($0.1)	$0.4	$0.1	$0.1	$0.1	($0.0)	$0.4	1,230	398
14	Everts Drive - South Troy	Line	PENELEC	$1.2	$1.5	($0.1)	($0.4)	$0.0	$0.0	$0.0	$0.1	($0.3)	3,934	154
15	Hummelstown - Middletown Jct	Line	Met-Ed	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	58	0
25	Sunbury	Transformer	PPL	$0.2	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	3,866	0
28	Conastone - Otter Creek	Line	PPL	($8.2)	($8.3)	($0.2)	($0.2)	$0.3	$0.7	$0.3	($0.0)	($0.2)	618	316
40	Steel City	Transformer	PPL	($0.0)	($0.1)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	838	0
43	Alburtis	Transformer	PPL	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	130	0
44	Middletown Jct - Brunner Island	Line	PPL	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	132	0

PSEG Control Zone

Table G-21 PSEG Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Emilie - Falls	Line	PECO	$20.6	$2.0	$1.4	$20.1	($0.2)	$0.6	($1.1)	($1.8)	$18.3	10,342	1,790
2	Cedar Grove - Clifton	Line	PSEG	$12.5	$3.9	$0.7	$9.4	($0.9)	$0.8	($1.7)	($3.4)	$6.0	2,358	158
3	Conastone - Peach Bottom	Line	500	($23.8)	($27.7)	($0.3)	$3.6	$0.8	$0.4	$0.4	$0.8	$4.4	6,318	1,680
4	Three Mile Island	Transformer	500	($7.0)	($8.1)	($0.1)	$0.9	$0.1	($0.2)	$0.1	$0.4	$1.3	1,080	172
5	Cedar Grove Sub - Roseland	Line	PSEG	$2.5	$0.7	$0.3	$2.1	($0.3)	$0.3	($0.5)	($1.0)	$1.0	710	108
6	Conastone - Otter Creek	Line	PPL	($12.6)	($12.3)	($0.2)	($0.5)	$0.3	($0.8)	$0.3	$1.4	$0.9	2,672	1,736
7	Athenia - Bergen	Line	PSEG	$0.2	$0.1	$0.0	$0.2	($0.1)	$0.1	($0.8)	($1.0)	($0.8)	88	22
8	Butler - Shanor Manor	Line	APS	($8.0)	($7.3)	($0.1)	($0.8)	$0.2	($0.0)	$0.1	$0.3	($0.5)	3,768	530
9	Kilmer - Sayreville	Line	PSEG	$0.4	($0.1)	$0.1	$0.6	$0.0	$0.0	($0.1)	($0.1)	$0.5	2,342	480
10	Bayway - Doremus	Line	PSEG	$0.2	($0.2)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	988	0
11	Hudson	Transformer	PSEG	$0.2	$0.0	$0.2	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	5,220	0
12	Nottingham	Other	PECO	($3.1)	($3.5)	($0.1)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	2,130	0
13	North Philadelphia - Waneeta	Line	PECO	($0.6)	($1.1)	($0.1)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	976	0
14	5004/5005 Interface	Interface	500	$10.9	$8.8	$0.0	$2.0	($0.0)	$1.5	($0.1)	($1.6)	$0.4	346	208
15	Federals - Newark	Line	PSEG	$0.3	($0.1)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	530	0
16	Linden - North Ave	Line	PSEG	$0.1	($0.2)	$0.1	$0.5	($0.0)	($0.1)	($0.2)	($0.1)	$0.4	3,410	60
23	Camden - Gloucester	Line	PSEG	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.3	162	122
28	Bergen - Fair Lawn	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.0	$0.2	$0.2	0	24
29	Bayway - Doremus Place	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	$0.2	$0.2	0	64
38	Hawthorn - Hinchmans Ave	Line	PSEG	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	280	2

Table G-22 PSEG Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	($75.7)	($81.6)	($1.2)	$4.7	$1.6	($4.3)	$1.0	$6.9	$11.7	5,552	3,680
2	Conastone - Peach Bottom	Line	500	($20.2)	($25.1)	($0.6)	$4.3	$0.3	($0.3)	$0.3	$0.9	$5.2	4,814	1,398
3	Bagley - Graceton	Line	BGE	($47.9)	($50.0)	($0.8)	$1.3	$0.8	($2.4)	$0.4	$3.6	$4.9	6,626	3,370
4	Emilie - Falls	Line	PECO	$5.4	$1.9	$0.6	$4.0	($0.0)	$0.3	($0.2)	($0.6)	$3.5	5,234	658
5	Cedar Grove Sub - Roseland	Line	PSEG	$6.0	$2.9	$0.3	$3.4	$0.0	$0.2	($0.3)	($0.4)	$3.0	2,006	46
6	Richmond - Waneeta	Line	PECO	($2.1)	($4.4)	($0.1)	$2.2	$0.1	$0.3	$0.4	$0.2	$2.5	624	176
7	Cedar Grove - Clifton	Line	PSEG	$3.3	$1.6	$0.4	$2.2	$0.0	$0.2	($0.1)	($0.3)	$1.9	924	48
8	Hudson	Transformer	PSEG	$0.9	$0.5	$1.1	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	5,590	0
9	Hawthorne - Hinchmans Ave	Line	PSEG	$1.6	$1.3	$1.2	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	130	0
10	Central East	Flowgate	NYISO	$0.2	$0.2	$0.0	$0.1	$0.0	$0.6	($0.9)	($1.5)	($1.4)	128	2,148
11	Linden - North Ave	Line	PSEG	$0.6	($0.2)	$0.3	$1.1	($0.0)	($0.0)	($0.1)	($0.2)	$1.0	2,316	126
12	Cedar Grove Sub - William	Line	PSEG	$0.4	$0.2	$0.0	$0.2	$0.0	$0.2	($1.0)	($1.2)	($1.0)	92	64
13	Graceton	Transformer	BGE	($45.8)	($42.2)	($0.6)	($4.2)	($0.0)	($3.0)	$0.4	$3.4	($0.8)	6,234	2,596
14	49th Street - Hoboken	Line	PSEG	$0.7	$0.7	$0.8	$0.8	($0.2)	$0.2	($0.9)	($1.4)	($0.6)	468	98
15	Plymouth Meeting - Whitpain	Line	PECO	($1.3)	($0.4)	($0.0)	($1.0)	$0.1	($0.2)	$0.0	$0.4	($0.6)	770	58
19	West Orange - Springfield Road	Other	PSEG	$0.7	$0.1	($0.2)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	60	0
20	Hudson - Kearny	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	186	0
23	Bergen	Other	PSEG	($0.0)	($0.2)	$0.0	$0.2	$0.0	($0.1)	$0.0	$0.1	$0.3	212	24
25	Kilmer - Sayreville	Line	PSEG	$0.4	$0.0	$0.1	$0.4	$0.0	$0.0	($0.1)	($0.1)	$0.3	2,316	12
26	Rad Essex - Newark Energy Center	Line	PSEG	$0.0	($0.3)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	84	0

RECO Control Zone

Table G-23 RECO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	500	($0.7)	($0.0)	($0.0)	($0.7)	$0.0	$0.0	$0.0	$0.0	($0.6)	6,318	1,680
2	Emilie - Falls	Line	PECO	$0.5	$0.0	$0.1	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.5	10,342	1,790
3	Graceton - Safe Harbor	Line	BGE	($0.5)	($0.0)	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.1	($0.5)	6,236	2,302
4	Cedar Grove - Clifton	Line	PSEG	$0.3	$0.0	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	2,358	158
5	Conastone - Otter Creek	Line	PPL	($0.4)	($0.0)	($0.0)	($0.4)	$0.0	$0.0	$0.1	$0.1	($0.3)	2,672	1,736
6	5004/5005 Interface	Interface	500	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	346	208
7	Butler - Shanor Manor	Line	APS	($0.3)	($0.0)	($0.0)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	3,768	530
8	Conastone - Northwest	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	1,950	456
9	Cedar Grove Sub - Roseland	Line	PSEG	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	710	108
10	Brunner Island - Yorkanna	Line	Met-Ed	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	$0.0	($0.1)	1,362	148
11	Three Mile Island	Transformer	500	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.1	$0.1	($0.1)	1,080	172
12	Roxana - Praxair	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	3,468	580
13	Pleasant View - Ashburn	Line	Dominion	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	$0.0	($0.1)	946	170
14	Bagley - Graceton	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,108	254
15	South Troy - Tennessee Gas Tap	Line	PENELEC	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	3,098	250
96	Closter - Harings Corners	Line	RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0
369	Burns - Corporate Road	Line	RECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	4	0

Table G-24 RECO Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	($2.0)	($0.2)	($0.1)	($1.9)	$0.1	$0.1	$0.1	$0.1	($1.8)	5,552	3,680
2	Graceton	Transformer	BGE	($1.4)	($0.1)	($0.2)	($1.5)	$0.0	$0.0	$0.2	$0.2	($1.3)	6,234	2,596
3	Bagley - Graceton	Line	BGE	($1.3)	($0.1)	($0.1)	($1.2)	$0.1	$0.1	$0.1	$0.1	($1.2)	6,626	3,370
4	Conastone - Peach Bottom	Line	500	($0.5)	($0.1)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	4,814	1,398
5	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.0)	($0.3)	($0.4)	($0.3)	128	2,148
6	Hawthorne - Hinchmans Ave	Line	PSEG	($0.2)	($0.0)	($0.1)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	130	0
7	Cedar Grove Sub - Roseland	Line	PSEG	$0.3	$0.0	($0.0)	$0.2	$0.0	($0.0)	($0.1)	($0.1)	$0.2	2,006	46
8	Mainesburg - Mansfield	Line	PENELEC	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.1)	($0.1)	($0.2)	4,196	282
9	Conastone - Otter Creek	Line	PPL	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	618	316
10	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.2	$0.2	$0.1	202	60
11	Bagley - Raphaerd	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,208	462
12	Brambleton - Loudoun	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	760	62
13	Person - Halifax	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	1,438	10
14	Plymouth Meeting - Whitpain	Line	PECO	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	770	58
15	Emilie - Falls	Line	PECO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	5,234	658
33	Burns - Corporate Road	Line	RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	116	0
34	Closter - Harings Corners	Line	RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	114	0

West Region Congestion-Event Summaries

AEP Control Zone

Table G-25 AEP Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Westwood	Flowgate	MISO	($17.1)	($33.5)	($2.0)	$14.4	$1.2	$0.7	$0.0	$0.5	$14.9	6,798	396
2	Greentown	Flowgate	MISO	$3.4	($2.5)	($1.3)	$4.6	($0.7)	($0.8)	$2.3	$2.4	$6.9	850	496
3	5004/5005 Interface	Interface	500	($17.9)	($24.0)	($0.3)	$5.8	$1.1	$1.5	$0.3	($0.0)	$5.8	346	208
4	AEP - DOM	Interface	500	($1.8)	($7.5)	$0.1	$5.8	$0.2	$0.3	($0.0)	($0.2)	$5.7	1,896	66
5	Cloverdale	Transformer	AEP	($3.7)	($8.0)	($0.0)	$4.3	$0.5	$2.2	($7.7)	($9.5)	($5.1)	600	166
6	AP South	Interface	500	($10.9)	($16.7)	($0.9)	$4.9	$0.3	$0.4	$0.2	$0.1	$5.1	2,630	148
7	Shadelnd - Lafaysouth	Flowgate	MISO	($3.8)	($6.9)	($0.5)	$2.6	$6.7	$4.2	($0.2)	$2.2	$4.8	2,110	1,338
8	Capital Hill - Chemical	Line	AEP	$2.6	($1.3)	$0.6	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1,470	0
9	Westwood	Transformer	MISO	$0.0	$0.0	$0.0	$0.0	$5.4	$1.9	($0.3)	$3.2	$3.2	0	1,576
10	Person - Sedge Hill	Line	Dominion	($14.8)	($17.8)	$0.2	$3.2	$0.6	$0.7	($0.5)	($0.6)	$2.6	2,498	420
11	Tanners Creek - Miami Fort	Line	AEP	($0.8)	($2.4)	($0.4)	$1.2	$0.0	$0.1	$1.1	$1.0	$2.2	2,426	126
12	Ohio Central - West Coshocton	Line	AEP	($0.2)	($2.7)	($0.1)	$2.3	($0.1)	($0.0)	$0.1	($0.0)	$2.2	1,374	38
13	Lake George - Aetna	Flowgate	MISO	($2.7)	($4.3)	($0.3)	$1.3	($0.5)	($0.2)	$1.0	$0.6	$1.9	966	488
14	Batesville - Hubble	Flowgate	MISO	($2.7)	($5.8)	($1.6)	$1.4	$0.4	$0.4	$0.4	$0.5	$1.9	758	316
15	Brokaw - Leroy	Flowgate	MISO	$4.5	$5.9	($1.0)	($2.3)	($0.4)	($0.3)	$0.5	$0.5	($1.9)	3,488	1,056
17	Iogtown - North Delphos	Line	AEP	($1.7)	($3.4)	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	3,752	0
22	Huntington Junction - Sorenson	Line	AEP	($0.1)	($1.4)	$0.3	$1.5	$0.2	($0.0)	($0.0)	$0.2	$1.7	2,204	16
28	Scottsville - Bremo	Line	AEP	$2.1	$0.8	$0.4	$1.6	($0.2)	($0.1)	($0.3)	($0.5)	$1.1	2,252	50
29	Delaware - Wes Del	Line	AEP	$0.4	$0.0	$0.1	$0.4	($0.8)	$0.4	($0.4)	($1.5)	($1.1)	194	78
31	LaPorte Junction	Transformer	AEP	$1.1	$0.2	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	3,682	0

Table G-26 AEP Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Reynolds - Magnetation	Flowgate	MISO	($0.2)	($15.9)	($0.7)	$15.0	$0.4	$0.8	($0.6)	($1.0)	$14.0	4,124	1,360
2	Kanawha River - Matt Funk	Line	AEP	$8.3	($10.1)	$0.2	$18.6	($0.8)	$1.9	($5.2)	($7.9)	$10.7	550	214
3	AEP - DOM	Interface	500	($0.1)	($7.4)	$0.9	$8.3	$0.1	$0.1	($0.9)	($0.9)	$7.4	3,208	10
4	Kanawha	Transformer	AEP	$3.9	($2.2)	$0.9	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	3,560	0
5	East Danville - Banister	Line	AEP	$5.3	$0.2	$1.0	$6.0	($0.1)	($0.1)	($0.1)	($0.1)	$5.9	7,286	40
6	Dumont	Flowgate	MISO	$4.5	($2.6)	($1.3)	$5.7	$0.0	$0.0	$0.0	$0.0	$5.7	944	0
7	Capital Hill - Chemical	Line	AEP	$2.1	($1.5)	$0.4	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1,170	0
8	Michigan City - Bosserman	Flowgate	MISO	$6.9	$4.5	$1.0	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	1,246	0
9	Westwood	Flowgate	MISO	$0.1	($3.0)	($0.4)	$2.7	$0.4	($0.1)	$0.2	$0.6	$3.4	1,900	274
10	Gomingo - Joshua Falls	Line	AEP	($0.7)	($3.6)	$0.5	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	1,040	0
11	Bosserman - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($1.5)	($0.3)	($1.7)	($2.8)	($2.8)	0	586
12	AP South	Interface	500	($10.2)	($13.2)	($0.4)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	2,152	28
13	South Millersburg - Buckhorn	Line	AEP	($1.6)	($4.7)	$0.1	$3.2	($0.3)	$0.6	($0.1)	($1.0)	$2.3	1,576	62
14	Bedington - Black Oak	Interface	500	($9.9)	($12.3)	($0.3)	$2.2	$0.1	$0.1	$0.1	$0.1	$2.2	3,030	210
15	Reynold - Monticello	Flowgate	MISO	$0.2	($2.8)	($0.0)	$2.9	$0.3	$0.8	($0.2)	($0.7)	$2.2	1,122	260
16	Cloverdale	Transformer	AEP	($0.7)	($2.8)	$0.6	$2.6	$0.0	$0.2	($0.4)	($0.6)	$2.0	1,720	104
17	Kammer	Transformer	AEP	$1.0	($1.7)	($0.1)	$2.6	$0.2	$0.5	($0.3)	($0.7)	$1.9	594	56
18	Kanawha River	Transformer	AEP	$1.1	($0.7)	$0.0	$1.8	$0.1	$0.1	$0.0	$0.1	$1.8	280	32
20	Chemical - Union Carbide Tap	Line	AEP	$1.3	($0.1)	$0.2	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	268	4
21	Monel - Reusens	Line	AEP	($0.1)	($1.3)	$0.4	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	962	138

APS Control Zone

Table G-27 APS Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	AP South	Interface	500	($2.1)	($8.2)	($0.2)	$5.9	$0.3	($0.4)	$0.3	$1.0	$7.0	2,630	148
2	Bedington - Black Oak	Interface	500	($0.5)	($3.3)	($0.3)	$2.5	$0.1	($0.0)	$0.4	$0.6	$3.1	2,430	122
3	Person - Sedge Hill	Line	Dominion	$1.1	($0.2)	$0.3	$1.7	$0.2	$0.0	($0.3)	($0.2)	$1.5	2,498	420
4	Carson - Rawlings	Line	Dominion	$1.1	($0.2)	$0.3	$1.6	$0.1	$0.0	($0.2)	($0.2)	$1.4	1,440	462
5	Butler - Shanor Manor	Line	APS	($1.5)	($0.4)	($1.1)	($2.2)	($0.0)	$0.0	$1.0	$1.0	($1.3)	3,768	530
6	5004/5005 Interface	Interface	500	($5.1)	($6.9)	($0.5)	$1.3	($0.0)	$0.7	$0.7	($0.1)	$1.2	346	208
7	Lakeview - Greenfield	Line	ATSI	$2.6	$1.9	$0.5	$1.3	($0.0)	$0.0	($0.2)	($0.2)	$1.1	3,186	328
8	Gardners - Texas East	Line	Met-Ed	$1.1	$0.2	$0.1	$1.0	$0.0	$0.0	$0.0	($0.0)	$1.0	2,634	232
9	Saxton - Three Springs	Line	PENELEC	($0.5)	($0.4)	($0.3)	($0.4)	$0.3	$0.1	($0.7)	($0.5)	($0.9)	1,776	302
10	Pleasant View - Ashburn	Line	Dominion	($1.6)	($0.7)	($0.4)	($1.2)	$0.0	$0.0	$0.3	$0.3	($0.9)	946	170
11	Edinburg - Strasburg	Line	Dominion	$0.6	$0.1	$0.1	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	804	36
12	Tiltonsville - Windsor	Line	APS	$1.1	$0.3	$0.0	$0.8	($0.0)	$0.0	($0.1)	($0.2)	$0.6	262	28
13	Edgewater - Vasco Tap	Line	APS	$1.1	$0.5	$0.1	$0.6	$0.1	$0.0	($0.2)	($0.0)	$0.6	436	58
14	Cloverdale	Transformer	AEP	$0.7	$0.2	$0.1	$0.6	$0.3	($0.0)	($0.3)	($0.0)	$0.6	600	166
15	AEP - DOM	Interface	500	($0.1)	($0.6)	($0.1)	$0.5	$0.0	$0.0	$0.0	$0.1	$0.5	1,896	66
18	Butler - Karns City	Line	APS	$0.7	$0.1	($0.1)	$0.5	($0.2)	$0.0	$0.2	($0.0)	$0.5	900	90
23	All Dam - Kittanning	Line	APS	($0.1)	($0.3)	($0.0)	$0.2	($0.0)	$0.0	$0.1	$0.1	$0.3	690	64
24	Albright - Kingwood	Line	APS	$0.1	($0.0)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	428	0
37	Beryl - Westvaco	Line	APS	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4,612	0
41	Meadow Brook - Strasburg	Line	APS	$0.2	($0.2)	($0.0)	$0.4	($0.3)	$0.0	$0.0	($0.3)	$0.1	1,232	88

Table G-28 APS Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Northwest	Line	BGE	$15.7	$10.4	($1.5)	$3.8	($0.3)	($0.1)	$1.4	$1.2	$5.0	5,552	3,680
2	AP South	Interface	500	($1.1)	($6.1)	($0.4)	$4.6	$0.0	$0.0	($0.0)	($0.0)	$4.6	2,152	28
3	Bedington - Black Oak	Interface	500	($0.4)	($5.6)	($0.9)	$4.4	$0.1	$0.0	$0.2	$0.2	$4.6	3,030	210
4	Person - Halifax	Flowgate	MISO	$2.8	$0.4	$1.3	$3.6	$0.0	($0.0)	($0.1)	($0.1)	$3.6	1,438	10
5	Loudoun	Transformer	Dominion	$0.1	($1.9)	($0.2)	$1.8	$0.2	$0.1	$1.6	$1.8	$3.5	800	138
6	502 Junction	Transformer	500	$2.4	($0.5)	($0.0)	$2.9	($0.0)	$0.0	($0.0)	($0.0)	$2.8	642	4
7	Bagley - Graceton	Line	BGE	$9.3	$6.8	($1.0)	$1.5	($0.0)	($0.1)	$1.0	$1.1	$2.7	6,626	3,370
8	Graceton	Transformer	BGE	$4.2	$2.5	($0.7)	$1.0	$0.2	($0.1)	$0.8	$1.0	$2.0	6,234	2,596
9	Brambleton - Loudoun	Line	Dominion	$1.6	$0.4	$0.2	$1.5	$0.1	$0.0	($0.0)	$0.1	$1.6	760	62
10	Person - Halifax	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.2	($0.0)	($1.5)	($1.3)	($1.3)	0	434
11	Kanawha	Transformer	AEP	$1.1	$0.4	$0.2	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	3,560	0
12	Meadow Brook - Strasburg	Line	APS	$0.7	($0.8)	($0.1)	$1.4	($1.0)	($0.2)	$0.3	($0.5)	$0.8	2,222	196
13	Roxbury	Transformer	PENELEC	$0.6	$0.2	$0.4	$0.8	($0.0)	$0.0	$0.0	($0.0)	$0.8	3,038	24
14	Yukon	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$0.7	$0.7	$0.7	0	32
15	Brambleton - Mosby	Line	500	$0.4	($0.1)	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	302	0
19	All Dam - Kittanning	Line	APS	($0.1)	($0.7)	($0.1)	$0.4	($0.0)	$0.0	$0.0	$0.0	$0.4	1,286	44
23	Butler - Karns City	Line	APS	$0.3	($0.1)	($0.1)	$0.3	($0.0)	$0.0	$0.1	$0.1	$0.3	886	20
27	St. Marys - Pleasants	Line	APS	$0.0	($0.1)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	1,506	0
32	Muskingum - Wolf Creek	Line	APS	$1.0	$1.2	$0.5	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	2,500	0
36	Klinesmill - Riverton	Line	APS	$0.1	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,122	0

ATSI Control Zone

Table G-29 ATSI Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Lakeview - Greenfield	Line	ATSI	$2.7	($7.8)	$0.8	$11.3	($0.3)	$1.4	($0.7)	($2.4)	$9.0	3,186	328
2	Butler - Shanor Manor	Line	APS	$13.4	$8.5	$1.4	$6.2	$0.2	($0.1)	($0.9)	($0.5)	$5.7	3,768	530
3	5004/5005 Interface	Interface	500	($10.0)	($8.7)	($0.3)	($1.6)	$0.2	$1.5	$0.2	($1.1)	($2.7)	346	208
4	AP South	Interface	500	($8.5)	($6.9)	($0.4)	($2.0)	($0.1)	$0.3	$0.2	($0.2)	($2.2)	2,630	148
5	Conastone - Peach Bottom	Line	500	$5.1	$3.5	($0.5)	$1.0	($0.2)	($0.2)	$0.7	$0.7	$1.7	6,318	1,680
6	Clinic Hospital - Inland	Line	ATSI	$1.8	$0.5	$0.2	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	860	0
7	Conastone - Otter Creek	Line	PPL	$3.5	$2.3	($0.3)	$0.9	($0.2)	($0.1)	$0.5	$0.5	$1.4	2,672	1,736
8	Person - Sedge Hill	Line	Dominion	($3.5)	($2.8)	$0.4	($0.4)	$0.1	$0.6	($0.4)	($0.9)	($1.2)	2,498	420
9	Roxana - Praxair	Flowgate	MISO	$5.1	$3.8	$0.5	$1.8	($0.1)	($0.1)	($0.7)	($0.7)	$1.1	3,468	580
10	Graceton - Safe Harbor	Line	BGE	$2.9	$1.9	($0.5)	$0.5	($0.1)	($0.1)	$0.6	$0.6	$1.1	6,236	2,302
11	Bedington - Black Oak	Interface	500	($3.5)	($2.7)	($0.1)	($0.9)	($0.0)	$0.1	$0.0	($0.1)	($1.0)	2,430	122
12	Cloverdale	Transformer	AEP	($1.2)	($1.1)	$0.0	($0.1)	$0.1	$0.5	($0.5)	($0.9)	($1.0)	600	166
13	Lakeview - Ottawa	Line	ATSI	$0.3	($0.5)	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	478	0
14	Ohio Central - West Coshocton	Line	AEP	$1.5	$0.9	$0.2	$0.8	$0.1	($0.1)	($0.0)	$0.1	$0.9	1,374	38
15	Central East	Flowgate	NYISO	($2.1)	($1.4)	($0.1)	($0.8)	($0.0)	$0.0	$0.0	($0.0)	($0.8)	1,030	664
26	Maple	Other	ATSI	$1.3	$0.9	$0.1	$0.5	($0.1)	($0.2)	($0.1)	($0.1)	$0.4	144	136
30	Crissinger - Delaware Business Park	Line	ATSI	$0.3	$0.1	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	590	0
34	BP Husky - Fort Industry	Line	ATSI	$0.0	$0.0	$0.0	$0.0	$0.2	($0.1)	($0.0)	$0.3	$0.3	0	16
37	Maple - Jackson	Line	ATSI	$0.7	$0.4	$0.1	$0.4	$0.0	($0.0)	($0.1)	($0.1)	$0.3	268	10
46	Carlisle - National Bronze	Line	ATSI	$0.1	($0.1)	($0.0)	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	24	4

Table G-30 ATSI Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Clinic Hospital - Inland	Line	ATSI	$4.7	$1.3	$0.4	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	1,232	0
2	Butler - Shanor Manor	Line	APS	$5.5	$3.4	$0.8	$2.9	($0.1)	($0.4)	($1.0)	($0.8)	$2.1	1,068	168
3	South Millersburg - Buckhorn	Line	AEP	$2.7	$1.9	$0.3	$1.2	$0.2	($0.2)	$0.4	$0.8	$2.0	1,576	62
4	Ottowa - West Fremont	Line	ATSI	($0.8)	($2.7)	$0.1	$1.9	$0.0	($0.0)	($0.1)	($0.0)	$1.9	712	22
5	Conastone - Peach Bottom	Line	500	$3.9	$2.4	($0.1)	$1.4	($0.1)	($0.1)	$0.2	$0.2	$1.6	4,814	1,398
6	AP South	Interface	500	($6.8)	($5.5)	($0.3)	($1.5)	$0.0	$0.0	$0.0	$0.0	($1.5)	2,152	28
7	Conastone - Northwest	Line	BGE	$0.6	($0.5)	($1.5)	($0.4)	($0.0)	($0.0)	$1.9	$1.8	$1.4	5,552	3,680
8	Bedington - Black Oak	Interface	500	($6.3)	($5.0)	($0.1)	($1.4)	$0.0	$0.1	$0.0	($0.0)	($1.4)	3,030	210
9	Person - Halifax	Flowgate	MISO	($5.4)	($4.0)	$0.1	($1.3)	$0.0	($0.0)	($0.0)	($0.0)	($1.3)	1,438	10
10	Kanawha River - Matt Funk	Line	AEP	($4.2)	($3.4)	($0.2)	($1.0)	$0.0	$0.4	$0.2	($0.1)	($1.1)	550	214
11	Lakeview - Greenfield	Line	ATSI	$0.6	($0.5)	$0.1	$1.2	($0.0)	$0.0	($0.1)	($0.1)	$1.1	684	50
12	Kirby - Robertoe	Line	ATSI	$1.0	$0.4	$0.4	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	1,442	0
13	Bagley - Graceton	Line	BGE	$0.2	($0.4)	($0.7)	($0.1)	($0.0)	($0.0)	$1.1	$1.1	$1.0	6,626	3,370
14	Loudoun	Transformer	Dominion	($2.9)	($2.0)	($0.1)	($0.9)	$0.2	$0.3	$0.1	$0.0	($0.9)	800	138
15	Kincaid - Pana North	Line	ComEd	$0.2	$0.1	$0.8	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	4,254	0
17	Lakeview - Ottawa	Line	ATSI	$0.4	($0.3)	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	230	0
23	Liberty - Lloyd	Line	ATSI	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	104	0
28	Mayfield - Pawnee	Line	ATSI	$0.5	$0.1	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	416	0
29	New Carlisle - Eutap	Line	ATSI	$0.4	$0.0	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	366	0
35	Ivy - Newburg	Line	ATSI	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	566	0

ComEd Control Zone

Table G-31 ComEd Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)									Event Hours	
				Day-Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Braidwood - East Frankfort	Line	ComEd	($4.9)	($50.0)	($0.4)	$44.8	$0.7	$2.0	$0.5	($0.7)	$44.0	8,342	602
2	Cherry Valley	Transformer	ComEd	$9.1	($9.9)	$1.8	$20.8	($0.7)	$0.6	($1.9)	($3.3)	$17.5	6,014	298
3	Alpine - Belvidere	Flowgate	MISO	$0.9	($10.7)	($0.9)	$10.7	$0.0	$0.0	$0.0	$0.0	$10.7	678	0
4	Brokaw - Leroy	Flowgate	MISO	($27.9)	($37.5)	($2.8)	$6.8	$0.7	$0.7	$2.4	$2.5	$9.3	3,488	1,056
5	Byron - Cherry Valley	Flowgate	MISO	$2.2	($6.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	694	0
6	Havana E - Havana S	Flowgate	MISO	($6.1)	($12.3)	$0.1	$6.3	$0.0	$0.0	$0.0	$0.0	$6.3	4,520	0
7	Westwood	Flowgate	MISO	$3.4	($2.4)	$0.4	$6.2	($0.0)	$0.1	($0.2)	($0.2)	$5.9	6,798	396
8	Quad Cities	Transformer	ComEd	($1.7)	($6.5)	($0.1)	$4.8	$0.0	$0.0	$0.0	$0.0	$4.8	18,914	0
9	Braidwood - Davis Creek	Line	ComEd	($0.3)	($4.9)	($0.2)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	170	0
10	5004/5005 Interface	Interface	500	($13.3)	($17.2)	($0.3)	$3.7	$0.2	($0.1)	$0.5	$0.8	$4.5	346	208
11	Nelson	Flowgate	MISO	$0.9	($3.6)	($0.3)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	1,068	0
12	Dresden	Flowgate	MISO	$5.1	$0.9	($0.2)	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	2,432	0
13	Person - Sedge Hill	Line	Dominion	($13.7)	($17.4)	($0.3)	$3.5	$0.3	$0.4	$0.6	$0.5	$3.9	2,498	420
14	Lake George - Aetna	Flowgate	MISO	$22.5	$15.6	$0.7	$7.6	($1.9)	$0.4	($1.5)	($3.8)	$3.9	966	488
15	Carson - Rawlings	Line	Dominion	($12.7)	($16.3)	($0.3)	$3.3	$0.3	$0.2	$0.3	$0.4	$3.7	1,440	462
19	Electric Junction - Lombard	Line	ComEd	$1.1	($1.4)	$0.1	$2.6	$0.1	$0.1	$0.3	$0.3	$2.9	654	26
20	Davis	Transformer	ComEd	$1.3	($1.5)	($0.1)	$2.7	($0.0)	$0.1	$0.1	$0.0	$2.7	812	34
27	East Frankfort	Transformer	ComEd	$2.2	$0.4	$0.1	$1.9	($0.0)	($0.0)	($0.0)	($0.0)	$1.9	1,380	20
35	Braidwood	Transformer	ComEd	($0.0)	($1.6)	$0.2	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	4,172	0
37	Quad Cities - Sterling Steel	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3	($1.4)	($1.7)	($1.7)	0	74

Table G-32 ComEd Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)									Event Hours	
				Day-Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Cherry Valley	Transformer	ComEd	$22.7	($25.9)	$4.1	$52.7	($3.0)	$2.2	($6.0)	($11.1)	$41.5	10,638	1,548
2	Cherry Valley	Flowgate	MISO	$7.9	($31.0)	$0.1	$39.0	$0.0	$0.0	$0.0	$0.0	$39.0	2,658	0
3	Braidwood - East Frankfort	Line	ComEd	($3.9)	($38.4)	$0.1	$34.6	$0.6	$3.4	($1.7)	($4.5)	$30.1	4,260	674
4	Mercer IP - Galesburg	Flowgate	MISO	($28.7)	($61.0)	($4.6)	$27.7	$0.2	$3.5	$1.1	($2.3)	$25.5	7,020	2,310
5	Byron - Cherry Valley	Flowgate	MISO	$0.6	($17.1)	$0.1	$17.9	$0.0	$0.0	$0.0	$0.0	$17.9	596	0
6	Dixon - McGirr Rd	Flowgate	MISO	$1.4	($17.1)	($1.4)	$17.0	$0.0	$0.0	$0.0	$0.0	$17.0	3,558	0
7	Electric Junction - Aurora Energy Center	Line	ComEd	($0.6)	($11.8)	($0.6)	$10.6	$0.1	$2.9	$1.2	($1.7)	$9.0	1,432	258
8	Cherry Valley - Silver Lake	Flowgate	MISO	($1.1)	($8.6)	$0.3	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	968	0
9	Braidwood - East Frankfurt	Flowgate	MISO	($2.1)	($9.7)	$0.0	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	1,232	0
10	Alpine - Belvidere	Flowgate	MISO	($0.3)	($8.0)	($0.3)	$7.3	$0.0	$0.0	$0.0	$0.0	$7.3	992	0
11	Davis	Transformer	ComEd	$2.7	($3.4)	$0.1	$6.2	$0.0	$0.1	$0.1	($0.0)	$6.2	1,946	14
12	Oak Grove - Galesburg	Flowgate	MISO	($5.3)	($10.8)	($0.1)	$5.4	$0.1	$0.2	$0.0	($0.1)	$5.3	2,672	348
13	Braidwood	Transformer	ComEd	($0.1)	($4.7)	$0.7	$5.3	$0.0	$0.0	$0.0	$0.0	$5.3	8,276	0
14	Conastone - Northwest	Line	BGE	$25.9	$31.0	$0.2	($4.9)	($0.7)	($0.5)	($0.2)	($0.4)	$5.2	5,552	3,680
15	Cherry Valley - Belvidere	Line	ComEd	$1.9	($6.9)	$0.7	$9.5	($1.1)	$1.8	($1.8)	($4.6)	$4.8	1,922	222
18	Byron - Cherry Valley	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.4	$2.3	($2.2)	($4.1)	$4.1	0	416
19	Mazon - La Salle	Line	ComEd	$0.5	($3.6)	($0.1)	$4.0	$0.1	$0.1	($0.1)	($0.1)	$3.9	1,510	76
21	Pleasant Valley - Belvidere	Line	ComEd	($0.5)	($3.0)	$0.3	$2.8	$0.0	$0.0	($0.0)	$0.0	$2.8	888	2
24	West Loop	Transformer	ComEd	$4.0	$1.6	($0.1)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	232	0
26	Cherry Valley - Sabrooke	Line	ComEd	$1.7	$0.4	$0.8	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	1,756	12

DAY Control Zone

Table G-33 DAY Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Lakeview - Greenfield	Line	ATSI	($2.1)	($1.3)	($0.2)	($1.0)	$0.0	($0.0)	$0.1	$0.2	($0.9)	3,186	328
2	5004/5005 Interface	Interface	500	($2.4)	($1.5)	($0.0)	($0.9)	$0.2	$0.2	$0.0	$0.1	($0.8)	346	208
3	Butler - Shanor Manor	Line	APS	$2.0	$1.4	$0.1	$0.8	$0.0	$0.1	($0.1)	($0.2)	$0.6	3,768	530
4	Batesville - Hubble	Flowgate	MISO	$3.2	$2.3	($0.1)	$0.8	$0.1	$0.2	($0.2)	($0.2)	$0.6	758	316
5	Person - Sedge Hill	Line	Dominion	($1.9)	($1.3)	$0.0	($0.6)	$0.1	$0.1	($0.0)	$0.0	($0.5)	2,498	420
6	Carson - Rawlings	Line	Dominion	($1.8)	($1.2)	$0.0	($0.5)	$0.0	$0.1	$0.0	($0.0)	($0.5)	1,440	462
7	Graceton - Safe Harbor	Line	BGE	$1.7	$1.2	$0.0	$0.5	($0.1)	$0.0	($0.0)	($0.1)	$0.4	6,236	2,302
8	AP South	Interface	500	($1.7)	($1.3)	($0.1)	($0.5)	($0.0)	($0.1)	$0.1	$0.1	($0.4)	2,630	148
9	Conastone - Peach Bottom	Line	500	$2.3	$1.6	$0.1	$0.7	($0.1)	$0.3	($0.0)	($0.4)	$0.4	6,318	1,680
10	Iogtown - North Delphos	Line	AEP	$0.3	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	3,752	0
11	Delaware - Watkins Tap	Line	AEP	$0.2	$0.1	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,096	0
12	Cloverdale	Transformer	AEP	($0.8)	($0.5)	($0.0)	($0.3)	$0.2	$0.1	($0.0)	$0.1	($0.2)	600	166
13	Todd Hunter	Flowgate	MISO	($0.3)	($0.1)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	1,976	0
14	Conastone - Northwest	Line	BGE	$0.5	$0.3	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	1,950	456
15	Brokaw - Leroy	Flowgate	MISO	$0.6	$0.5	($0.1)	$0.1	($0.0)	($0.0)	$0.1	$0.1	$0.2	3,488	1,056
53	Stuart	Transformer	DAY	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	764	0
84	Trenton - Hutchings	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	192	0
133	Darby - Watkins Tap	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	52	0
145	West Milton - Greenville	Line	DAY	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	2
309	Stuart - Killen	Line	DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

Table G-34 DAY Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Delaware - Watkins Tap	Line	AEP	$0.7	$0.2	$0.5	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	3,802	0
2	Person - Halifax	Flowgate	MISO	($3.1)	($2.6)	($0.0)	($0.5)	$0.0	$0.0	$0.0	($0.0)	($0.5)	1,438	10
3	Kanawha River - Matt Funk	Line	AEP	($1.4)	($1.1)	($0.0)	($0.3)	($0.0)	$0.1	$0.0	($0.1)	($0.4)	550	214
4	Kirby - Robertoe	Line	ATSI	($0.4)	($0.2)	($0.1)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	1,442	0
5	Miami Fort - Clifty Creek	Line	DEOK	$0.5	$0.3	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	1,612	36
6	Bedington - Black Oak	Interface	500	($1.4)	($1.2)	($0.0)	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	3,030	210
7	AP South	Interface	500	($1.5)	($1.4)	($0.1)	($0.2)	$0.0	($0.0)	$0.0	$0.0	($0.2)	2,152	28
8	Summer ShadeTVA - Summer Shade Tap	Flowgate	MISO	$0.1	$0.2	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.1)	($0.2)	446	62
9	Conastone - Northwest	Line	BGE	$3.8	$4.1	($0.0)	($0.3)	($0.1)	($0.2)	$0.0	$0.1	($0.2)	5,552	3,680
10	Miami Fort - Willey	Line	DEOK	$0.4	$0.4	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	2,578	2
11	Germantown - Hutchings	Line	DAY	$0.1	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	784	0
12	Kammer - West Bellaire	Line	AEP	($0.5)	($0.5)	($0.0)	$0.0	($0.0)	($0.1)	$0.1	$0.2	$0.2	452	34
13	Batesville - Hubble	Flowgate	MISO	$1.7	$1.4	$0.1	$0.3	$0.1	($0.1)	($0.3)	($0.2)	$0.1	838	268
14	Person - Halifax	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$0.0	($0.1)	($0.1)	0	434
15	Reynolds - Magnetation	Flowgate	MISO	($0.2)	($0.2)	($0.1)	($0.1)	$0.0	($0.0)	($0.1)	($0.1)	($0.1)	4,124	1,360
53	Trenton - Hutchings	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	256	0
107	Stuart	Transformer	DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	610	0
330	Darby - Watkins Tap	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
339	Greene - Clark	Line	DAY	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	130	0
443	College Corner - Drewersburg	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	14	0

DEOK Control Zone

Table G-35 DEOK Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Batesville - Hubble	Flowgate	MISO	$16.6	$6.3	$0.2	$10.5	($0.4)	($0.7)	($2.5)	($2.2)	$8.3	758	316
2	Todd Hunter	Flowgate	MISO	$2.0	($1.0)	($0.1)	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	1,976	0
3	Miami Fort	Transformer	DEOK	$1.5	($0.3)	$0.1	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	4,352	2
4	Tanners Creek - Miami Fort	Line	AEP	$2.3	$0.7	$0.3	$1.9	($0.3)	($0.1)	$0.1	($0.1)	$1.8	2,426	126
5	Tanners Creek - Miami Fort	Flowgate	MISO	$1.0	$0.1	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	148	0
6	East Bend	Transformer	DEOK	($0.0)	($0.9)	($0.1)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	8,928	0
7	Butler - Shanor Manor	Line	APS	$2.8	$2.0	$0.1	$0.8	$0.0	$0.0	($0.1)	($0.1)	$0.8	3,768	530
8	5004/5005 Interface	Interface	500	($3.3)	($2.6)	($0.0)	($0.6)	($0.0)	$0.0	$0.0	($0.0)	($0.7)	346	208
9	Graceton - Safe Harbor	Line	BGE	$2.5	$2.0	$0.1	$0.6	($0.0)	($0.0)	($0.1)	($0.1)	$0.6	6,236	2,302
10	Conastone - Peach Bottom	Line	500	$3.4	$2.6	$0.1	$0.8	($0.1)	$0.1	($0.0)	($0.2)	$0.6	6,318	1,680
11	Person - Sedge Hill	Line	Dominion	($2.9)	($2.2)	($0.0)	($0.7)	$0.0	($0.1)	($0.0)	$0.1	($0.6)	2,498	420
12	Carson - Rawlings	Line	Dominion	($2.7)	($2.2)	($0.0)	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.5)	1,440	462
13	AP South	Interface	500	($2.2)	($1.8)	($0.0)	($0.4)	($0.0)	$0.1	$0.0	($0.1)	($0.5)	2,630	148
14	Lakeview - Greenfield	Line	ATSI	($2.4)	($1.9)	($0.1)	($0.6)	($0.0)	($0.0)	$0.1	$0.1	($0.5)	3,186	328
15	Roxana - Praxair	Flowgate	MISO	$1.8	$1.3	$0.1	$0.6	$0.0	$0.0	($0.1)	($0.1)	$0.5	3,468	580
28	Miami Fort - Willey	Line	DEOK	$0.1	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.1)	$0.0	$0.2	206	22
30	Miami Fort - Hebron	Line	DEOK	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.1)	($0.1)	($0.1)	0	16
34	Terminal	Transformer	DEOK	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	108	0
40	Silver Grove	Other	DEOK	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	224	0
42	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	50	0

Table G-36 DEOK Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Batesville - Hubble	Flowgate	MISO	$8.6	$2.8	$0.4	$6.2	($0.1)	($0.6)	($1.5)	($1.1)	$5.1	838	268
2	Miami Fort - Clifty Creek	Line	DEOK	$4.8	$1.5	$0.6	$3.9	$0.0	($0.0)	($0.1)	($0.0)	$3.9	1,612	36
3	Conastone - Northwest	Line	BGE	$5.7	$3.2	($0.0)	$2.4	$0.0	($0.3)	$0.0	$0.4	$2.8	5,552	3,680
4	Person - Halifax	Flowgate	MISO	($4.5)	($2.2)	$0.0	($2.2)	$0.0	$0.0	$0.0	$0.0	($2.2)	1,438	10
5	Miami Fort - Willey	Line	DEOK	$1.8	$0.6	$0.3	$1.5	$0.0	($0.0)	($0.0)	$0.0	$1.5	2,578	2
6	Miami Fort	Transformer	DEOK	$0.5	($0.5)	$0.1	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	6,004	8
7	Bagley - Graceton	Line	BGE	$3.6	$2.5	$0.1	$1.2	($0.0)	($0.1)	($0.1)	($0.0)	$1.2	6,626	3,370
8	Kanawha River - Matt Funk	Line	AEP	($1.9)	($1.0)	($0.1)	($1.0)	($0.0)	$0.2	$0.0	($0.2)	($1.2)	550	214
9	E.K.P Hebron - Hebron	Line	EKPC	$0.4	$0.1	$0.5	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	6,032	0
10	AP South	Interface	500	($1.9)	($1.1)	($0.0)	($0.8)	$0.0	$0.0	$0.0	$0.0	($0.8)	2,152	28
11	Bedington - Black Oak	Interface	500	($1.9)	($1.1)	($0.0)	($0.8)	($0.0)	$0.0	$0.0	($0.0)	($0.8)	3,030	210
12	Terminal	Flowgate	MISO	$0.4	($0.4)	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	374	0
13	Conastone - Peach Bottom	Line	500	$2.3	$1.6	$0.0	$0.7	($0.0)	($0.1)	($0.0)	$0.1	$0.7	4,814	1,398
14	Graceton	Transformer	BGE	$1.8	$1.2	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.0	$0.7	6,234	2,596
15	Kincaid - Pana North	Line	ComEd	$0.2	$0.1	$0.6	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	4,254	0
19	East Bend	Transformer	DEOK	($0.0)	($0.6)	($0.2)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	5,400	0
22	Port Union	Transformer	DEOK	$0.2	($0.2)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	204	2
23	Miami Fort - Greendale	Line	DEOK	$0.3	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	186	0
27	Terminal	Transformer	DEOK	$0.1	($0.1)	$0.0	$0.2	$0.0	($0.1)	$0.1	$0.1	$0.3	266	10
46	Fairfield - Willey	Line	DEOK	$0.2	($0.0)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0

DLCO Control Zone

Table G-37 DLCO Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)									Event Hours	
				Day-Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Butler - Shanor Manor	Line	APS	$2.2	$3.2	$0.2	($0.8)	($0.0)	($0.0)	($0.1)	($0.1)	($0.9)	3,768	530
2	5004/5005 Interface	Interface	500	($2.2)	($2.8)	($0.0)	$0.6	($0.0)	$0.1	$0.0	($0.2)	$0.5	346	208
3	Lakeview - Greenfield	Line	ATSI	$1.8	$2.4	$0.2	($0.3)	$0.0	($0.1)	($0.1)	($0.0)	($0.4)	3,186	328
4	Conastone - Peach Bottom	Line	500	$0.9	$1.2	($0.0)	($0.3)	($0.0)	($0.0)	$0.0	$0.0	($0.2)	6,318	1,680
5	Conastone - Otter Creek	Line	PPL	$0.6	$0.9	($0.0)	($0.3)	($0.0)	($0.0)	$0.0	$0.1	($0.2)	2,672	1,736
6	Roxana - Praxair	Flowgate	MISO	$1.0	$1.2	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	3,468	580
7	Clinton - Findlay	Line	DLCO	$0.4	$0.0	$0.0	$0.4	($0.0)	$0.0	($0.1)	($0.2)	$0.2	212	20
8	AP South	Interface	500	($1.9)	($2.2)	($0.1)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	2,630	148
9	Edgewater - Vasco Tap	Line	APS	$0.4	$0.2	$0.0	$0.2	$0.0	($0.1)	($0.1)	$0.0	$0.2	436	58
10	Brokaw - Leroy	Flowgate	MISO	$0.4	$0.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	3,488	1,056
11	Dravosburg - West Mifflin	Line	DLCO	($0.0)	($0.0)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	($0.2)	($0.2)	18	40
12	Person - Sedge Hill	Line	Dominion	($0.4)	($0.5)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.1	2,498	420
13	Batesville - Hubble	Flowgate	MISO	($0.1)	($0.1)	($0.0)	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	758	316
14	Carson - Rawlings	Line	Dominion	($0.3)	($0.5)	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.1	1,440	462
15	Arsenal - Brunot Island	Line	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	136	0
19	Arsenal - Oakland	Line	DLCO	$0.0	($0.1)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	48	26
25	Crescent - Montour	Line	DLCO	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	48	0
26	Crescent - Mt Nebo	Line	DLCO	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	116	0
29	Cheswick - Logan's Ferry	Line	DLCO	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	28	0
36	Cheswick - Logans Ferry	Line	DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	14

Table G-38 DLCO Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)									Event Hours	
				Day-Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Arsenal - Oakland	Line	DLCO	$0.4	($0.4)	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	420	0
2	Crescent - Sewickley	Line	DLCO	$0.6	$0.0	$0.1	$0.6	($0.1)	$0.0	($0.2)	($0.3)	$0.3	246	102
3	AP South	Interface	500	($1.4)	($1.7)	($0.1)	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	2,152	28
4	Butler - Shanor Manor	Line	APS	$0.9	$1.2	$0.1	($0.2)	$0.1	$0.0	($0.1)	($0.1)	($0.2)	1,068	168
5	Roxana - Praxair	Flowgate	MISO	$0.5	$0.7	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	1,768	896
6	Person - Halifax	Flowgate	MISO	($0.5)	($0.7)	($0.0)	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	1,438	10
7	502 Junction	Transformer	500	$0.3	$0.2	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	642	4
8	Kanawha River - Matt Funk	Line	AEP	($0.7)	($0.9)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	550	214
9	Clinton - Findlay	Line	DLCO	$0.1	($0.0)	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	310	4
10	Lakeview - Greenfield	Line	ATSI	$0.3	$0.4	$0.0	($0.1)	$0.0	$0.0	($0.1)	($0.1)	($0.2)	684	50
11	Toronto - Wylie Ridge	Line	ATSI	$0.0	$0.0	$0.0	$0.0	$0.1	($0.0)	($0.2)	($0.1)	($0.1)	22	10
12	Crescent	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	170	0
13	Conastone - Peach Bottom	Line	500	$0.8	$0.9	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($0.0)	($0.1)	4,814	1,398
14	AEP - DOM	Interface	500	($0.4)	($0.5)	($0.0)	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	3,208	10
15	Loudoun	Transformer	Dominion	($0.5)	($0.6)	($0.0)	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	800	138
20	Arsenal - Brunot Island	Line	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	116	0
28	Crescent - Mt Nebo	Line	DLCO	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	64	0
35	Brunot Island - Collier	Line	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
36	Beaver Valley - Raccoon	Line	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	22	0
44	Brunot Island - Forbes	Line	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	40	0

EKPC Control Zone

Table G-39 EKPC Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Batesville - Hubble	Flowgate	MISO	($3.0)	$0.1	($0.6)	($3.7)	$0.6	($0.3)	$0.5	$1.4	($2.3)	758	316
2	Person - Sedge Hill	Line	Dominion	($2.0)	($1.0)	($0.1)	($1.1)	$0.1	$0.1	$0.1	$0.2	($0.9)	2,498	420
3	Carson - Rawlings	Line	Dominion	($1.8)	($0.9)	($0.1)	($1.0)	$0.0	($0.0)	$0.0	$0.1	($0.9)	1,440	462
4	5004/5005 Interface	Interface	500	($1.8)	($1.2)	($0.0)	($0.7)	$0.2	$0.2	$0.0	$0.0	($0.7)	346	208
5	Conastone - Peach Bottom	Line	500	$1.6	$0.9	$0.1	$0.8	($0.1)	($0.0)	($0.1)	($0.2)	$0.6	6,318	1,680
6	Graceton - Safe Harbor	Line	BGE	$1.2	$0.7	$0.1	$0.6	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	6,236	2,302
7	Westwood	Flowgate	MISO	($0.5)	($0.1)	$0.0	($0.4)	$0.0	$0.0	($0.0)	($0.0)	($0.4)	6,798	396
8	Cloverdale	Transformer	AEP	($0.8)	($0.5)	($0.0)	($0.3)	$0.2	$0.2	$0.0	$0.0	($0.3)	600	166
9	Butler - Shanor Manor	Line	APS	$1.1	$0.7	$0.1	$0.5	($0.1)	$0.1	($0.0)	($0.2)	$0.3	3,768	530
10	Conastone - Otter Creek	Line	PPL	$1.0	$0.6	$0.1	$0.5	($0.0)	($0.0)	($0.1)	($0.1)	$0.3	2,672	1,736
11	Roxana - Praxair	Flowgate	MISO	$0.8	$0.5	$0.1	$0.3	($0.0)	$0.0	($0.0)	($0.1)	$0.3	3,468	580
12	Summer ShadeTVA - Summer Shade Tap	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.1)	($0.3)	($0.3)	0	0
13	East Bend	Transformer	DEOK	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	8,928	0
14	Greentown	Flowgate	MISO	($0.3)	($0.1)	($0.0)	($0.3)	$0.0	$0.0	$0.1	$0.0	($0.2)	850	496
15	Brokaw - Leroy	Flowgate	MISO	$0.5	$0.2	($0.0)	$0.3	($0.0)	($0.0)	($0.1)	($0.0)	$0.2	3,488	1,056
20	Summer Shade Tap - Summer Shade	Line	EKPC	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	318	0
29	Liberty Church - Farley	Line	EKPC	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	116	10
47	E.K.P Hebron - Hebron	Line	EKPC	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	2,308	0
66	Russell County - Russell Springs	Line	EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	46	0
88	Barren County	Transformer	EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	30	0

Table G-40 EKPC Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Summer ShadeTVA - Summer Shade Tap	Flowgate	MISO	$1.4	$0.1	$0.3	$1.6	($2.4)	$0.2	($0.7)	($3.2)	($1.7)	446	62
2	Batesville - Hubble	Flowgate	MISO	($1.2)	$0.4	($0.2)	($1.7)	$0.1	$0.1	$0.2	$0.2	($1.5)	838	268
3	Person - Halifax	Flowgate	MISO	($3.2)	($1.8)	($0.0)	($1.4)	$0.0	($0.0)	($0.0)	$0.0	($1.4)	1,438	10
4	Conastone - Northwest	Line	BGE	$3.1	$2.1	($0.1)	$0.9	($0.2)	($0.2)	$0.1	$0.0	$1.0	5,552	3,680
5	Summer Shade Tap - Summer Shade	Line	EKPC	$0.8	$0.0	$0.2	$0.9	($0.2)	($0.0)	($0.1)	($0.3)	$0.7	1,614	12
6	Bagley - Graceton	Line	BGE	$2.0	$1.4	$0.1	$0.7	($0.2)	($0.1)	($0.1)	($0.2)	$0.5	6,626	3,370
7	AEP - DOM	Interface	500	($0.1)	($0.3)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	3,208	10
8	Conastone - Peach Bottom	Line	500	$1.1	$0.8	$0.0	$0.4	($0.1)	($0.1)	($0.0)	($0.1)	$0.3	4,814	1,398
9	Miami Fort - Willey	Line	DEOK	($0.2)	$0.1	($0.0)	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	2,578	2
10	Graceton	Transformer	BGE	$1.0	$0.7	$0.0	$0.3	($0.1)	($0.0)	$0.0	($0.0)	$0.3	6,234	2,596
11	AP South	Interface	500	($1.0)	($0.7)	($0.0)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	2,152	28
12	Reynolds - Magnetation	Flowgate	MISO	($0.4)	($0.2)	$0.0	($0.2)	$0.0	$0.0	($0.1)	($0.0)	($0.2)	4,124	1,360
13	Bedington - Black Oak	Interface	500	($0.9)	($0.7)	($0.0)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.2)	3,030	210
14	Kammer - West Bellaire	Line	AEP	($0.3)	($0.3)	($0.0)	($0.1)	$0.0	($0.3)	$0.0	$0.3	$0.2	452	34
15	Miami Fort - Clifty Creek	Line	DEOK	($0.1)	$0.1	$0.0	($0.2)	$0.0	($0.0)	$0.0	$0.0	($0.2)	1,612	36
23	J.B. Galloway - Summer Shade	Line	EKPC	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	184	0
27	E.K.P Hebron - Hebron	Line	EKPC	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	6,032	0
29	Barren County	Transformer	EKPC	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	112	0
30	Sumshade	Transformer	EKPC	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	46	0
42	Green County - Greensburg	Line	EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	86	0

South Region Congestion-Event Summaries

Dominion Control Zone

Table G-41 Dominion Control Zone top congestion cost impacts (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Carson - Rawlings	Line	Dominion	$29.5	$18.0	$0.2	$11.7	$0.7	$1.5	($0.2)	($1.0)	$10.7	1,440	462
2	Pleasant View - Ashburn	Line	Dominion	$29.6	$19.1	$0.7	$11.2	($1.6)	($0.4)	($1.3)	($2.5)	$8.7	946	170
3	AP South	Interface	500	$37.0	$29.1	($0.6)	$7.2	($0.6)	$0.9	$0.2	($1.3)	$5.9	2,630	148
4	Crozet - Dooms	Line	Dominion	$8.7	$6.4	$0.2	$2.5	$0.5	$1.2	$0.2	($0.5)	$2.0	932	114
5	Bedington - Black Oak	Interface	500	$12.1	$10.1	$0.3	$2.4	($0.2)	$0.1	($0.1)	($0.4)	$1.9	2,430	122
6	Conastone - Otter Creek	Line	PPL	$28.7	$26.8	$0.5	$2.4	($0.2)	($0.3)	($0.6)	($0.6)	$1.9	2,672	1,736
7	Loudoun	Transformer	Dominion	$2.5	$0.7	($0.1)	$1.7	($0.0)	($0.0)	$0.1	$0.1	$1.8	332	6
8	Person - Sedge Hill	Line	Dominion	$34.3	$30.2	$1.4	$5.4	$0.0	$1.5	($2.3)	($3.7)	$1.7	2,498	420
9	Meadow Brook - Strasburg	Line	APS	$1.0	($0.1)	$0.0	$1.1	($0.1)	($0.2)	$0.1	$0.2	$1.3	1,232	88
10	Charlottesville - Proffit D.P.	Line	Dominion	$2.6	$1.6	$0.4	$1.5	($0.0)	$0.1	($0.1)	($0.2)	$1.3	1,772	20
11	Graceton - Safe Harbor	Line	BGE	$41.0	$39.7	$0.5	$1.8	($0.3)	($0.2)	($0.5)	($0.7)	$1.2	6,236	2,302
12	AEP - DOM	Interface	500	$10.4	$9.4	$0.1	$1.1	$0.1	$0.1	($0.1)	($0.1)	$1.1	1,896	66
13	Butler - Shanor Manor	Line	APS	($0.1)	$0.7	($0.3)	($1.1)	($0.0)	($0.0)	$0.2	$0.2	($0.8)	3,768	530
14	Carolina - Lakeview	Line	Dominion	$1.7	$1.0	$0.1	$0.8	$0.1	$0.1	($0.1)	($0.1)	$0.7	156	6
15	Cloverdale	Transformer	AEP	$8.3	$6.6	$0.1	$1.8	$0.3	$0.7	($0.7)	($1.2)	$0.6	600	166
16	Edinburg - Strasburg	Line	Dominion	($0.2)	($1.0)	($0.1)	$0.7	($0.1)	$0.1	$0.0	($0.2)	$0.6	804	36
18	Bremo - Cartersville	Line	Dominion	$0.6	$0.3	$0.0	$0.3	$0.8	$1.7	$0.1	($0.8)	($0.5)	44	20
20	Lexington	Transformer	Dominion	$1.5	$1.1	$0.2	$0.6	($0.1)	$0.2	$0.2	($0.1)	$0.5	228	24
22	Everetts - Greenville	Line	Dominion	$0.1	$0.1	$0.0	$0.1	($0.0)	$0.2	($0.3)	($0.5)	($0.4)	20	16
24	Sedge Hill	Transformer	Dominion	$0.4	$0.2	$0.2	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	802	14

Table G-42 Dominion Control Zone top congestion cost impacts (By facility): 2016

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day-Ahead	Real-Time
1	Loudoun	Transformer	Dominion	$1.0	($10.5)	($0.7)	$10.8	$0.1	$1.1	$1.8	$0.8	$11.6	800	138
2	Conastone - Northwest	Line	BGE	$174.0	$162.3	$1.9	$13.6	($1.5)	$0.6	($1.5)	($3.6)	$10.0	5,552	3,680
3	AP South	Interface	500	$31.8	$25.7	($0.7)	$5.3	($0.0)	$0.0	($0.0)	($0.0)	$5.3	2,152	28
4	Bremo	Transformer	Dominion	($2.7)	($7.4)	($0.1)	$4.6	$0.1	$0.0	$0.1	$0.2	$4.9	2,948	484
5	Bagley - Graceton	Line	BGE	$110.2	$105.9	$1.5	$5.8	($1.0)	($0.4)	($1.2)	($1.8)	$3.9	6,626	3,370
6	Pleasant View - Ashburn	Line	Dominion	$10.4	$6.6	$0.1	$3.9	($0.1)	($0.1)	($0.0)	($0.1)	$3.9	106	10
7	Meadow Brook - Strasburg	Line	APS	$9.5	$6.5	$0.1	$3.0	($0.1)	($0.5)	$0.5	$0.8	$3.8	2,222	196
8	Bedington - Black Oak	Interface	500	$18.8	$15.9	$0.4	$3.4	($0.1)	$0.0	($0.1)	($0.2)	$3.2	3,030	210
9	Graceton	Transformer	BGE	$81.7	$78.5	$1.1	$4.3	($0.7)	($0.1)	($0.8)	($1.4)	$2.8	6,234	2,596
10	Brambleton - Loudoun	Line	Dominion	($21.3)	($24.4)	($0.7)	$2.4	($0.4)	($0.1)	$0.6	$0.3	$2.7	760	62
11	Conastone - Peach Bottom	Line	500	$36.6	$34.6	$0.5	$2.5	($0.2)	($0.0)	($0.3)	($0.5)	$2.0	4,814	1,398
12	Person - Halifax	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.5	$0.2	($2.0)	($1.6)	($1.6)	0	434
13	Brambleton - Mosby	Line	500	($5.3)	($6.6)	($0.2)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	302	0
14	Brambleton	Transformer	Dominion	$2.0	$1.0	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	32	0
15	Person - Halifax	Flowgate	MISO	$62.3	$64.2	$1.0	($0.9)	$0.0	$0.0	($0.1)	($0.1)	($1.0)	1,438	10
17	Sherwood - Transco	Line	Dominion	$0.1	($0.8)	$0.0	$0.9	$0.1	$0.1	($0.0)	($0.1)	$0.9	574	188
20	Kidds Store D.P. - Transco	Line	Dominion	$0.1	($0.4)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	390	0
22	Chaparral - Locks	Line	Dominion	$0.7	$0.3	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	214	0
26	Basin - Chesterfield	Line	Dominion	($0.1)	($0.5)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	278	0
27	Loudoun - Cub-Run D.P.	Line	Dominion	$0.1	($0.2)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	12	0

Marginal Losses

Zonal Marginal Loss Costs

Table G-43 provides marginal loss costs by control zone and type for 2017. Table G-44 provides total marginal loss costs by control zone and month for 2016 and 2017. The total marginal loss cost for the External category was -$5.0 million in 2017.

Table G-43 Marginal loss costs by control zone and type (Dollars (Millions)): 2017

Marginal Loss Costs by Control Zone (Millions)										
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$1.8	($3.1)	$0.8	$5.8	$0.1	($0.1)	($1.1)	($0.8)	$0.0	$5.0
AEP	($48.3)	($211.0)	$15.9	$178.6	$4.3	$3.5	($25.5)	($24.7)	$0.0	$153.9
APS	($0.1)	($40.8)	$3.1	$43.8	$0.5	$0.0	($5.7)	($5.3)	$0.0	$38.5
ATSI	$25.4	($22.2)	$10.9	$58.5	$0.1	$1.2	($16.6)	($17.7)	$0.0	$40.8
BGE	$35.5	$12.8	$4.5	$27.2	($0.3)	($0.7)	($4.8)	($4.5)	$0.0	$22.8
ComEd	($126.4)	($255.6)	($3.3)	$125.9	$5.2	($1.9)	($2.1)	$4.9	$0.0	$130.8
DAY	$11.1	($13.6)	$8.2	$33.0	($0.2)	($0.7)	($9.4)	($8.9)	$0.0	$24.1
DEOK	($15.7)	($28.4)	$1.7	$14.3	$0.5	($0.2)	($1.8)	($1.1)	$0.0	$13.2
DLCO	($3.3)	($10.8)	$1.2	$8.7	$0.0	$0.0	($1.6)	($1.7)	$0.0	$7.0
Dominion	$74.7	$5.3	$2.8	$72.2	$2.1	$0.7	($5.0)	($3.6)	$0.0	$68.5
DPL	$11.0	($0.5)	$2.7	$14.2	($0.4)	($1.1)	($3.7)	($2.9)	$0.0	$11.3
EKPC	($9.5)	($11.8)	$1.0	$3.3	$0.5	$0.4	($1.7)	($1.6)	$0.0	$1.7
External	($14.3)	($13.4)	$2.0	$1.0	($3.7)	($1.4)	($3.8)	($6.0)	$0.0	($5.0)
JCPL	$3.6	($2.9)	$0.5	$7.0	$0.5	$0.1	($0.8)	($0.4)	$0.0	$6.6
Met-Ed	($0.5)	($16.9)	($0.5)	$15.8	$0.3	($0.0)	$0.2	$0.5	$0.0	$16.3
PECO	($4.0)	($34.9)	$0.4	$31.3	$0.8	$0.2	($0.9)	($0.2)	$0.0	$31.1
PENELEC	($36.4)	($82.5)	$1.3	$47.4	($0.3)	$0.4	($2.7)	($3.4)	$0.0	$44.0
Pepco	$46.8	$29.0	$0.9	$18.7	($0.2)	($1.5)	($1.2)	$0.1	$0.0	$18.8
PPL	($14.2)	($49.7)	($1.6)	$33.9	$1.0	$0.2	$0.9	$1.7	$0.0	$35.6
PSEG	$10.3	($16.3)	$2.3	$29.0	$0.2	$1.2	($2.5)	($3.4)	$0.0	$25.5
RECO	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.1)	($0.1)	$0.0	$0.3
Total	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8

Table G-44 Monthly marginal loss costs by control zone (Dollars (Millions)): 2016 and 2017

Marginal Loss Costs by Control Zone (Millions)														
2016														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$0.6	$0.5	$0.3	$0.2	$0.2	$0.6	$1.7	$1.4	$0.7	$0.3	$0.1	$0.7	($0.0)	$7.2
AEP	$14.7	$10.8	$7.4	$9.9	$6.9	$11.7	$20.0	$19.8	$14.0	$10.5	$8.8	$15.5	($0.0)	$149.9
APS	$4.5	$3.4	$2.1	$2.4	$2.3	$3.1	$4.5	$4.8	$3.7	$2.8	$2.0	$3.5	($0.0)	$39.3
ATSI	$3.7	$3.8	$4.1	$3.9	$2.6	$3.5	$4.9	$4.7	$4.5	$3.3	$2.8	$3.3	($0.0)	$45.1
BGE	$2.8	$2.2	$1.0	$1.2	$1.4	$1.9	$3.4	$3.1	$2.0	$1.3	$1.3	$2.2	($0.0)	$23.8
ComEd	$13.1	$10.2	$7.5	$9.9	$6.4	$9.9	$14.6	$13.6	$11.3	$9.0	$9.3	$13.1	($0.0)	$128.0
DAY	$2.4	$2.6	$2.1	$1.6	$1.6	$2.2	$2.8	$4.1	$2.9	$2.1	$1.8	$3.4	($0.0)	$29.7
DEOK	($0.5)	($0.3)	$0.0	($0.5)	$0.3	$1.0	$0.8	$1.1	$0.9	$1.1	$0.8	$1.1	($0.0)	$5.9
DLCO	$0.9	$0.5	$0.1	$0.5	$0.7	$0.6	$0.9	$0.7	$0.7	$0.4	$0.8	$0.9	($0.0)	$7.7
Dominion	$7.3	$6.0	$4.1	$4.3	$3.7	$6.1	$9.9	$9.7	$6.5	$3.7	$3.9	$5.9	($0.0)	$71.2
DPL	$2.0	$1.2	$0.4	$0.5	$0.4	$0.9	$2.6	$2.3	$1.1	$0.6	$0.6	$1.1	($0.0)	$13.7
EKPC	$0.4	$0.7	$0.2	$0.3	$0.3	$0.6	$0.8	$0.6	$0.2	$0.1	($0.2)	$0.7	($0.0)	$4.7
External	$4.5	$2.9	$1.4	$1.8	$0.8	($0.7)	($0.6)	($0.3)	($0.5)	($1.3)	($0.2)	($0.2)	$0.0	$7.6
JCPL	$0.9	$0.6	$0.3	$0.4	$0.4	$0.5	$1.0	$1.0	$0.6	$0.4	$0.4	$0.6	($0.0)	$7.1
Met-Ed	$1.2	$1.2	$1.1	$1.1	$0.8	$1.2	$1.6	$1.7	$1.5	$1.1	$1.1	$1.1	($0.0)	$14.9
PECO	$2.0	$2.0	$2.4	$2.0	$2.0	$2.2	$3.1	$3.4	$2.9	$2.5	$1.8	$2.3	($0.0)	$28.7
PENELEC	$3.8	$3.0	$1.7	$2.1	$2.0	$3.2	$4.6	$4.9	$3.5	$2.3	$2.3	$4.7	($0.0)	$37.9
Pepco	$2.3	$1.5	$0.8	$1.1	$0.8	$1.1	$2.3	$2.2	$1.6	$1.1	$1.1	$1.6	($0.0)	$17.4
PPL	$2.7	$2.2	$1.2	$1.4	$1.7	$1.9	$4.7	$4.1	$3.2	$1.9	$2.1	$3.3	($0.0)	$30.2
PSEG	$2.6	$2.4	$2.3	$2.0	$1.2	$1.5	$2.5	$2.7	$2.5	$1.7	$1.5	$2.9	($0.0)	$25.8
RECO	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.2	$0.1	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.6
Total	$72.0	$57.5	$40.6	$46.1	$36.6	$53.1	$86.4	$85.8	$64.0	$45.0	$42.1	$67.5	($0.0)	$696.5
Marginal Loss Costs by Control Zone (Millions)														
2017														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$0.5	$0.4	$0.5	$0.3	$0.1	$0.4	$0.9	$0.6	$0.3	$0.2	$0.1	$0.8	$0.0	$5.0
AEP	$15.2	$11.4	$15.0	$8.9	$11.9	$11.9	$15.6	$12.6	$9.6	$9.2	$9.1	$23.5	$0.0	$153.9
APS	$3.8	$2.7	$3.5	$2.5	$2.0	$2.6	$4.0	$3.4	$2.9	$2.6	$3.2	$5.3	$0.0	$38.5
ATSI	$3.0	$2.6	$4.7	$2.6	$3.4	$3.3	$3.9	$3.3	$3.1	$3.3	$3.7	$4.0	$0.0	$40.8
BGE	$2.6	$1.9	$2.5	$1.6	$1.1	$1.7	$2.6	$2.0	$1.5	$1.3	$1.1	$2.9	$0.0	$22.8
ComEd	$11.3	$8.4	$11.5	$10.0	$9.8	$9.8	$12.0	$9.4	$10.1	$9.9	$10.7	$17.8	$0.0	$130.8
DAY	$1.6	$0.9	$2.1	$2.0	$2.3	$2.3	$2.6	$2.3	$1.9	$1.9	$2.0	$2.1	$0.0	$24.1
DEOK	$1.0	$1.2	$1.2	$1.1	$1.0	$1.3	$1.0	$0.9	$1.3	$1.1	$1.2	$1.0	$0.0	$13.2
DLCO	$0.7	$0.5	$0.6	$0.4	$0.4	$0.6	$0.7	$0.6	$0.6	$0.5	$0.6	$0.9	$0.0	$7.0
Dominion	$6.3	$4.0	$5.2	$4.1	$5.4	$5.9	$8.7	$6.1	$5.7	$4.9	$4.5	$7.6	$0.0	$68.5
DPL	$0.7	$0.8	$1.0	$0.5	$0.4	$0.8	$1.6	$1.1	$0.6	$0.4	$0.4	$3.0	$0.0	$11.3
EKPC	$0.0	($0.1)	($0.1)	($0.2)	$0.2	$0.3	$0.4	$0.4	$0.5	$0.3	$0.1	($0.0)	$0.0	$1.7
External	$0.9	$0.5	$0.1	($1.6)	($1.5)	($0.7)	($1.4)	($1.1)	($1.1)	($0.9)	($0.4)	$2.1	$0.0	($5.0)
JCPL	$0.5	$0.4	$0.6	$0.5	$0.5	$0.5	$0.6	$0.5	$0.5	$0.3	$0.2	$1.6	$0.0	$6.6
Met-Ed	$1.4	$1.0	$1.1	$1.0	$1.6	$1.4	$1.7	$1.4	$1.3	$1.0	$1.7	$1.7	$0.0	$16.3
PECO	$2.2	$1.7	$2.6	$2.0	$2.8	$3.1	$3.3	$2.6	$3.0	$2.3	$2.9	$2.4	$0.0	$31.1
PENELEC	$3.8	$2.5	$4.3	$3.0	$4.0	$3.6	$4.9	$3.7	$3.3	$3.0	$3.3	$4.6	$0.0	$44.0
Pepco	$1.8	$1.5	$1.6	$1.2	$1.1	$1.4	$2.1	$1.7	$1.4	$1.3	$1.3	$2.5	$0.0	$18.8
PPL	$2.4	$2.1	$2.3	$2.4	$2.5	$2.4	$3.8	$3.0	$3.3	$3.1	$3.8	$4.5	$0.0	$35.6
PSEG	$2.7	$2.0	$2.4	$1.7	$1.2	$2.1	$2.5	$2.3	$2.3	$1.5	$1.8	$3.1	$0.0	$25.5
RECO	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.1	$0.0	$0.3
Total	$62.3	$46.4	$62.8	$44.2	$50.1	$54.8	$71.6	$56.8	$52.0	$47.1	$51.3	$91.5	$0.0	$690.8

Energy

Zonal Energy Costs

Table G-45 provides energy costs by control zone and type for 2017. Table G-46 provides total energy costs by control zone and month for 2016 and 2017. The total energy cost for the External category in 2017 was $464.1 million.

Table G-45 Energy costs by control zone and type (Dollars (Millions)): 2017

Energy Costs by Control Zone (Millions)										
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$340.4	$253.3	$0.0	$87.1	($1.1)	($12.5)	$0.0	$11.5	$0.1	$98.7
AEP	$4,887.9	$5,804.6	$0.0	($916.7)	($128.3)	($152.3)	$0.0	$23.9	$1.1	($891.7)
APS	$1,629.9	$1,605.1	$0.0	$24.8	($9.1)	($15.7)	$0.0	$6.5	$0.4	$31.8
ATSI	$2,485.4	$1,729.4	$0.0	$756.0	($47.2)	($70.0)	$0.0	$22.8	$0.6	$779.4
BGE	$1,618.2	$1,292.3	$0.0	$325.9	($20.0)	($18.6)	$0.0	($1.5)	$0.3	$324.7
ComEd	$4,295.6	$5,080.2	$0.0	($784.7)	($105.1)	($1.1)	$0.0	($104.0)	$0.9	($887.8)
DAY	$652.3	$477.5	$0.0	$174.8	($12.5)	$0.2	$0.0	($12.6)	$0.2	$162.3
DEOK	$911.9	$707.6	$0.0	$204.3	($9.3)	($11.8)	$0.0	$2.6	$0.2	$207.1
DLCO	$476.1	$569.7	$0.0	($93.6)	($3.6)	($11.3)	$0.0	$7.7	$0.1	($85.8)
Dominion	$5,737.0	$5,690.4	$0.0	$46.7	($24.5)	($21.5)	$0.0	($3.0)	$0.9	$44.6
DPL	$624.1	$301.1	$0.0	$323.1	($15.6)	($9.4)	$0.0	($6.2)	$0.2	$317.1
EKPC	$415.1	$264.4	$0.0	$150.7	($26.5)	($16.5)	$0.0	($10.0)	$0.1	$140.8
External	$827.7	$455.3	$0.0	$372.4	$161.4	$69.7	$0.0	$91.7	$0.0	$464.1
JCPL	$755.4	$635.0	$0.0	$120.4	($6.9)	($15.9)	$0.0	$9.0	$0.2	$129.6
Met-Ed	$556.9	$752.8	$0.0	($195.9)	($4.4)	($15.9)	$0.0	$11.6	$0.1	($184.2)
PECO	$1,424.4	$2,125.2	$0.0	($700.8)	($26.4)	($12.2)	$0.0	($14.2)	$0.4	($714.6)
PENELEC	$2,392.8	$3,289.1	$0.0	($896.3)	($23.6)	($135.8)	$0.0	$112.2	$0.2	($783.9)
Pepco	$2,495.2	$1,945.4	$0.0	$549.8	($16.2)	($77.7)	$0.0	$61.5	$0.3	$611.5
PPL	$1,497.5	$1,786.7	$0.0	($289.2)	($13.8)	($35.1)	$0.0	$21.3	$0.3	($267.5)
PSEG	$1,418.9	$1,369.6	$0.0	$49.3	($4.6)	$61.3	$0.0	($65.9)	$0.4	($16.2)
RECO	$47.2	$3.8	$0.0	$43.4	($0.9)	($2.2)	$0.0	$1.3	$0.0	$44.7
Total	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)

Table G-46 Monthly energy costs by control zone (Dollars (Millions)): 2016 and 2017

Energy Costs by Control Zone (Millions)														
2016														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$9.8	$5.6	$2.9	$5.9	$8.9	$6.1	$17.5	$17.3	$8.1	$2.4	$10.1	$6.6	($0.1)	$100.8
AEP	($27.6)	($12.5)	$3.5	($24.8)	($4.2)	($71.3)	($116.9)	($105.9)	($65.4)	($30.9)	($29.5)	($72.2)	($1.6)	($559.5)
APS	$10.6	$8.8	$14.8	$17.9	($6.3)	($4.9)	$0.9	($2.8)	($3.9)	($16.1)	$10.3	$6.7	($0.6)	$35.2
ATSI	$49.2	$53.5	$80.7	$67.2	$44.9	$55.2	$63.0	$82.0	$60.2	$43.5	$48.9	$81.6	($0.9)	$728.9
BGE	$36.3	$34.8	$13.4	$8.4	$18.5	$21.6	$36.7	$34.8	$22.3	$11.6	$13.5	$26.4	($0.4)	$277.9
ComEd	($75.6)	($54.1)	($45.8)	($67.0)	($23.4)	($41.8)	($62.3)	($50.2)	($68.0)	($77.3)	($71.7)	($102.6)	($1.3)	($741.1)
DAY	$12.2	$0.4	($1.0)	$3.3	$2.5	$9.4	$14.2	$0.8	$4.5	$4.3	$3.4	$1.8	($0.2)	$55.6
DEOK	$42.7	$34.1	$28.6	$44.5	$19.7	$19.5	$35.5	$29.2	$21.6	$10.2	$10.1	$19.8	($0.3)	$315.1
DLCO	($7.4)	($2.6)	($13.0)	($14.2)	($12.0)	($2.3)	($5.6)	($1.7)	$0.0	$1.9	($10.2)	($13.9)	($0.2)	($81.2)
Dominion	$8.7	($11.6)	($10.7)	$23.3	($9.4)	($27.9)	($25.8)	($21.4)	($0.6)	$22.2	$12.3	$8.6	($1.2)	($33.5)
DPL	$36.8	$29.1	$17.6	$15.6	$16.8	$17.7	$25.4	$27.4	$20.1	$14.3	$20.4	$39.8	($0.2)	$280.9
EKPC	$15.4	$7.8	$6.8	$5.0	$4.1	$4.3	$3.2	$5.6	$6.2	$6.2	$13.4	$6.4	($0.1)	$84.3
External	($82.0)	($62.6)	($49.6)	($41.6)	($24.7)	$47.4	$43.6	$41.1	$53.4	$59.2	$21.0	$31.2	$0.0	$36.3
JCPL	$19.7	$12.1	$7.8	$4.8	$10.9	$12.7	$22.0	$22.8	$16.7	($0.2)	$1.0	$19.5	($0.3)	$149.5
Met-Ed	($16.2)	($17.3)	($15.6)	($21.0)	($10.4)	($17.5)	($16.5)	($16.5)	($19.5)	($12.6)	($16.8)	$1.1	($0.2)	($179.0)
PECO	($56.6)	($47.7)	($61.7)	($56.2)	($55.2)	($50.4)	($58.6)	($54.3)	($62.6)	($51.1)	($52.7)	($69.5)	($0.5)	($677.2)
PENELEC	($54.1)	($41.8)	($17.1)	($30.3)	($27.5)	($47.1)	($70.4)	($71.8)	($50.4)	($28.8)	($45.2)	($85.8)	($0.2)	($570.5)
Pepco	$63.7	$43.2	$36.5	$44.9	$36.1	$44.4	$51.1	$53.0	$42.4	$35.7	$50.3	$66.2	($0.4)	$567.0
PPL	($26.4)	($20.8)	$0.5	$1.1	($17.9)	($19.8)	($62.1)	($47.7)	($28.6)	($14.0)	($18.5)	($21.5)	($0.5)	($276.2)
PSEG	($10.9)	($0.2)	($28.2)	($20.3)	($0.0)	$7.5	$42.2	($2.3)	($0.0)	($10.0)	$0.1	($1.6)	($0.6)	($24.4)
RECO	$3.6	$3.0	$2.6	$2.8	$2.9	$3.8	$6.2	$6.0	$4.2	$3.1	$2.7	$3.9	($0.0)	$44.8
Total	($48.4)	($39.0)	($27.3)	($30.8)	($25.8)	($33.3)	($56.9)	($54.7)	($39.2)	($26.4)	($27.2)	($47.6)	($9.8)	($466.3)
Energy Costs by Control Zone (Millions)														
2017														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$6.1	$4.6	$3.3	$4.6	$13.3	$9.1	$17.1	$11.2	$6.8	$5.1	$4.6	$12.8	$0.1	$98.7
AEP	($89.9)	($73.6)	($88.7)	($39.5)	($84.1)	($88.7)	($107.2)	($84.6)	($33.7)	($26.3)	($20.0)	($156.5)	$1.1	($891.7)
APS	$7.4	$9.8	$14.5	$1.6	$20.0	$3.2	($6.9)	($7.4)	($12.5)	($9.5)	($7.1)	$18.3	$0.4	$31.8
ATSI	$82.1	$64.7	$93.9	$52.2	$53.3	$63.8	$65.4	$62.0	$51.4	$66.9	$48.6	$74.5	$0.6	$779.4
BGE	$32.9	$30.4	$37.4	$23.8	$15.4	$28.9	$34.8	$29.2	$18.2	$20.6	$17.3	$35.4	$0.3	$324.7
ComEd	($94.4)	($49.2)	($78.5)	($92.1)	($80.1)	($49.1)	($60.6)	($46.6)	($59.0)	($80.8)	($83.0)	($115.2)	$0.9	($887.8)
DAY	$23.1	$19.8	$11.1	$3.4	$7.0	$13.1	$14.3	$11.7	$12.6	$8.9	$11.6	$25.5	$0.2	$162.3
DEOK	$19.0	$2.4	$8.0	$6.0	$32.3	$17.4	$34.9	$21.2	$18.5	$12.3	$11.3	$23.7	$0.2	$207.1
DLCO	($8.0)	($8.6)	($11.1)	($4.6)	$6.2	($7.6)	($5.6)	($6.1)	($7.4)	($13.6)	($5.7)	($13.7)	$0.1	($85.8)
Dominion	$2.6	$6.0	($2.4)	$11.0	$12.7	($15.7)	($14.7)	($7.0)	($6.3)	$9.4	$5.5	$42.6	$0.9	$44.6
DPL	$39.3	$23.9	$26.3	$22.2	$14.9	$22.3	$26.8	$25.4	$21.2	$19.9	$28.8	$45.9	$0.2	$317.1
EKPC	$13.8	$10.8	$13.9	$14.2	$7.9	$7.7	$9.9	$6.5	$8.3	$11.0	$16.7	$20.0	$0.1	$140.8
External	$0.8	$11.7	$27.8	$57.6	$49.6	$49.3	$61.1	$48.9	$55.5	$36.5	$26.9	$38.5	$0.0	$464.1
JCPL	$13.8	$7.2	$8.9	$14.3	$4.5	$9.5	$17.5	$8.2	$1.1	$5.5	$12.6	$26.3	$0.2	$129.6
Met-Ed	($16.9)	($17.1)	($1.7)	($11.1)	($24.7)	($16.8)	($19.3)	($14.8)	($14.9)	($9.2)	($21.1)	($16.8)	$0.1	($184.2)
PECO	($69.6)	($59.0)	($80.1)	($60.5)	($50.8)	($58.2)	($58.2)	($55.5)	($56.1)	($50.6)	($57.6)	($58.8)	$0.4	($714.6)
PENELEC	($70.8)	($51.7)	($81.9)	($56.7)	($71.4)	($59.3)	($76.4)	($66.4)	($52.2)	($52.2)	($43.6)	($101.4)	$0.2	($783.9)
Pepco	$63.3	$45.4	$55.9	$46.1	$45.5	$53.4	$56.2	$54.0	$40.3	$46.9	$44.4	$59.7	$0.3	$611.5
PPL	($3.0)	($10.9)	$21.0	($15.0)	($15.9)	($21.9)	($43.9)	($38.6)	($34.2)	($42.1)	($37.1)	($26.4)	$0.3	($267.5)
PSEG	($1.8)	($1.1)	($23.3)	($12.0)	$7.2	($1.7)	$3.0	$4.5	($0.4)	$2.5	$8.1	($1.6)	$0.4	($16.2)
RECO	$3.7	$2.6	$3.5	$3.0	$3.5	$4.1	$5.2	$4.2	$4.1	$3.3	$3.2	$4.4	$0.0	$44.7
Total	($46.7)	($31.8)	($42.3)	($31.5)	($33.6)	($37.1)	($46.6)	($40.0)	($38.9)	($35.5)	($35.6)	($62.7)	$7.1	($475.2)

Appendix H FTR Volumes

This Appendix presents the data used to create Figure 13-8 in the 2017 State of the Market Report for PJM. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the cleared buy, cleared sell and self-scheduled offers. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Annual Auction volume is included in June of each planning period.

Table H-1 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003/2004

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-03	2,679,072	89,840	2,690,737
Jul-03	295,753	8,642	300,808
Aug-03	215,206	9,978	220,241
Sep-03	226,994	9,068	234,315
Oct-03	127,739	10,522	135,885
Nov-03	114,211	8,247	122,362
Dec-03	131,180	8,352	139,221
Jan-04	128,086	10,947	136,657
Feb-04	128,303	12,187	137,790
Mar-04	144,617	13,827	156,543
Apr-04	141,437	17,358	157,776
May-04	168,480	44,641	178,973
Total	4,501,077	243,608	4,611,308

Table H-2 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004/2005

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-04	939,214	125,044	1,019,868
Jul-04	160,472	21,761	190,198
Aug-04	144,402	22,650	176,642
Sep-04	155,837	13,999	194,229
Oct-04	180,542	49,816	226,156
Nov-04	213,036	23,912	247,780
Dec-04	226,271	18,384	260,964
Jan-05	212,061	22,549	236,135
Feb-05	276,385	20,700	305,613
Mar-05	306,472	25,712	348,416
Apr-05	307,297	36,914	330,088
May-05	280,690	32,545	300,966
Total	3,402,681	413,987	3,837,056

Table H-3 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005/2006

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-05	1,011,821	159,049	1,120,404
Jul-05	300,153	23,929	340,891
Aug-05	233,493	17,966	276,936
Sep-05	222,404	22,133	266,577
Oct-05	147,493	18,906	189,458
Nov-05	183,750	20,525	227,432
Dec-05	200,886	19,422	244,608
Jan-06	234,473	21,431	275,081
Feb-06	250,308	26,463	293,774
Mar-06	272,662	31,968	317,705
Apr-06	431,398	36,603	472,732
May-06	384,767	38,977	424,962
Total	3,873,608	437,372	4,450,561

Table H-4 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006/2007

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-06	2,274,846	198,380	2,533,660
Jul-06	719,494	31,662	934,424
Aug-06	738,375	26,392	932,469
Sep-06	630,072	37,351	841,698
Oct-06	710,045	51,193	888,011
Nov-06	765,177	40,110	890,318
Dec-06	757,683	42,848	919,549
Jan-07	778,266	59,813	905,249
Feb-07	884,953	68,179	969,447
Mar-07	661,938	69,754	799,130
Apr-07	455,411	30,963	551,601
May-07	432,783	37,207	480,219
Total	9,809,046	693,852	11,645,776

Table H-5 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007/2008

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-07	2,961,754	323,632	3,462,015
Jul-07	794,490	51,248	1,068,961
Aug-07	944,015	63,392	1,224,668
Sep-07	901,284	66,611	1,200,730
Oct-07	973,936	112,427	1,245,797
Nov-07	841,326	61,592	1,059,631
Dec-07	1,276,687	49,825	1,461,068
Jan-08	501,642	27,377	655,581
Feb-08	583,749	37,288	676,847
Mar-08	437,241	31,941	590,524
Apr-08	326,050	34,805	427,105
May-08	280,005	22,837	331,327
Total	10,822,178	882,975	13,404,256

Table H-6 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008/2009

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-08	3,511,130	339,654	3,832,169
Jul-08	968,615	53,843	1,211,784
Aug-08	961,694	40,027	1,224,054
Sep-08	925,250	64,901	1,127,274
Oct-08	802,966	52,768	965,756
Nov-08	607,441	45,707	738,336
Dec-08	550,352	37,633	748,485
Jan-09	488,102	43,739	673,525
Feb-09	492,216	40,439	639,274
Mar-09	391,938	42,722	581,075
Apr-09	299,908	35,685	440,629
May-09	222,092	21,016	295,198
Total	10,221,706	818,134	12,477,560

Table H-7 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009/2010

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-09	2,652,340	307,584	3,156,826
Jul-09	488,748	41,389	849,742
Aug-09	414,151	55,261	708,452
Sep-09	427,221	56,998	718,246
Oct-09	538,476	64,328	797,069
Nov-09	559,750	65,577	745,333
Dec-09	447,221	68,470	672,986
Jan-10	529,887	64,435	728,765
Feb-10	490,391	62,153	670,272
Mar-10	389,934	73,069	615,690
Apr-10	345,301	66,017	489,638
May-10	291,537	52,036	375,812
Total	7,574,956	977,318	10,528,830

Table H-8 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010/2011

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-10	3,177,131	428,603	3,894,566
Jul-10	720,172	102,883	1,145,991
Aug-10	859,260	93,226	1,202,137
Sep-10	1,079,947	144,423	1,510,812
Oct-10	1,041,425	120,281	1,427,494
Nov-10	922,444	111,442	1,261,969
Dec-10	1,005,436	157,609	1,359,582
Jan-11	902,052	132,866	1,207,101
Feb-11	931,164	160,750	1,184,383
Mar-11	952,963	182,340	1,250,283
Apr-11	660,480	138,230	913,583
May-11	620,691	169,610	762,538
Total	12,873,166	1,942,261	17,120,443

Table H-9 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011/2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Jan-12	772,843	88,683	1,240,355
Feb-12	816,356	93,977	1,234,341
Mar-12	665,949	99,659	1,126,207
Apr-12	449,078	131,218	795,785
May-12	295,103	94,642	470,495
Total	16,523,352	2,259,688	22,891,036

Table H-10 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2012/2013

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-12	6,407,647	710,169	7,598,008
Jul-12	2,177,990	182,695	2,735,269
Aug-12	909,111	151,693	1,418,249
Sep-12	1,877,747	146,352	2,446,553
Oct-12	788,486	118,052	1,310,859
Nov-12	1,765,875	98,494	2,142,231
Dec-12	1,757,292	115,322	2,230,391
Jan-13	696,121	121,357	1,067,354
Feb-13	805,330	118,298	1,129,794
Mar-13	854,219	132,779	1,196,032
Apr-13	525,505	97,353	790,360
May-13	477,217	87,001	595,463
Total	15,684,148	1,522,778	19,881,561

Table H-11 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2013/2014

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-13	6,607,570	791,995	7,909,805
Jul-13	2,000,987	189,328	2,571,100
Aug-13	2,193,738	239,816	2,726,508
Sep-13	2,046,401	260,404	2,604,664
Oct-13	1,692,645	222,661	2,233,085
Nov-13	1,823,502	237,130	2,307,163
Dec-13	1,795,279	216,021	2,298,733
Jan-14	1,713,078	185,284	2,092,055
Feb-14	1,588,809	157,166	1,979,691
Mar-14	1,560,077	169,500	1,918,025
Apr-14	1,247,111	127,436	1,559,987
May-14	757,354	80,601	934,844
Total	25,026,550	2,877,341	31,135,659

Table H-12 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2014/2015

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-14	8,631,333	744,482	9,600,316
Jul-14	2,365,262	123,067	2,689,241
Aug-14	2,191,719	154,391	2,513,616
Sep-14	2,232,435	167,077	2,636,101
Oct-14	1,935,928	153,735	2,289,409
Nov-14	2,006,939	175,554	2,339,892
Dec-14	1,831,645	116,545	2,138,480
Jan-15	1,586,530	81,368	1,849,891
Feb-15	1,446,978	110,669	1,701,821
Mar-15	1,395,961	97,219	1,684,143
Apr-15	1,194,256	78,599	1,429,386
May-15	699,951	42,698	817,152
Total	27,518,938	2,045,403	31,689,447

Table H-13 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2015/2016

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-15	6,726,193	634,988	7,956,486
Jul-15	1,713,451	90,329	2,341,646
Aug-15	1,593,674	78,196	2,046,131
Sep-15	2,160,014	160,357	2,628,872
Oct-15	1,196,435	71,600	1,704,518
Nov-15	2,060,194	92,310	2,482,819
Dec-15	1,834,874	93,273	2,239,329
Jan-16	2,033,402	151,198	2,374,385
Feb-16	2,305,964	89,153	2,610,677
Mar-16	2,085,527	151,835	2,444,912
Apr-16	1,393,628	117,292	1,663,102
May-16	658,850	59,976	780,265
Total	25,762,206	1,790,507	31,273,141

Table H-14 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2016/2017

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-16	6,208,065	701,086	7,476,215
Jul-16	2,219,166	161,129	2,751,687
Aug-16	2,130,193	166,317	2,611,601
Sep-16	1,876,699	151,538	2,379,705
Oct-16	1,522,572	149,106	1,920,453
Nov-16	1,191,214	106,349	1,542,444
Dec-16	995,951	66,497	1,341,292
Jan-17	1,042,674	60,087	1,305,937
Feb-17	998,397	76,384	1,233,142
Mar-17	846,294	105,822	1,141,063
Apr-17	653,571	70,885	897,780
May-17	463,486	59,067	595,694
Total	20,148,281	1,874,268	25,197,013

Table H-15 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2017/2018 through December 2017

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-17	5,455,078	872,195	6,469,151
Jul-17	2,003,170	257,105	2,530,997
Aug-17	1,703,960	178,490	2,240,951
Sep-17	1,372,384	181,542	1,863,571
Oct-17	1,172,291	150,774	1,649,567
Nov-17	1,327,717	105,816	1,697,539
Dec-17	1,366,297	131,964	1,662,660
Total	14,400,896	1,877,886	18,114,436

Figure H-1 summarizes the total revenue associated with all FTRs, regardless of source, to FTR sinks that produced the largest positive and negative revenue from the 2017/2020 Long Term FTR Auction. The top 10 positive revenue producing FTR sinks accounted for $48.7 million (28.7 percent of the total positive revenue from sinks) and 4.7 percent of all FTRs purchased in the auction. The top 10 negative revenue producing FTR sinks accounted for -$60.0 million (42.1 percent of total negative revenue from sinks) and constituted 3.0 percent of all FTRs bought in the auction.

Figure H-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2017/2020

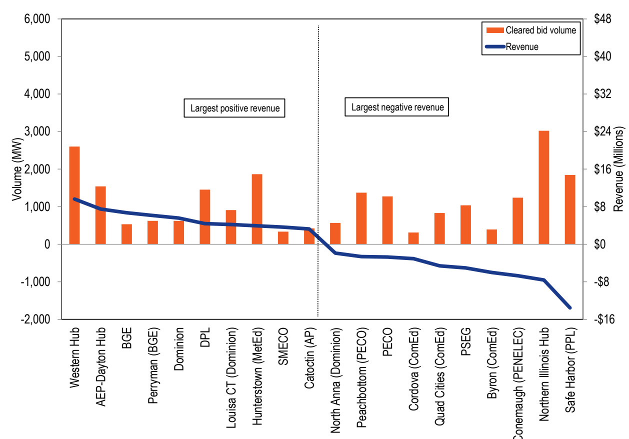


Figure H-2 summarizes the total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2017/2020 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $54.9 million (33.0 percent of the total positive revenue from sources) and 4.2 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$53.9 million (38.5 percent of total negative revenue from sources) and constituted 4.6 percent of all FTRs bought in the auction.

Figure H-2 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2017/2020

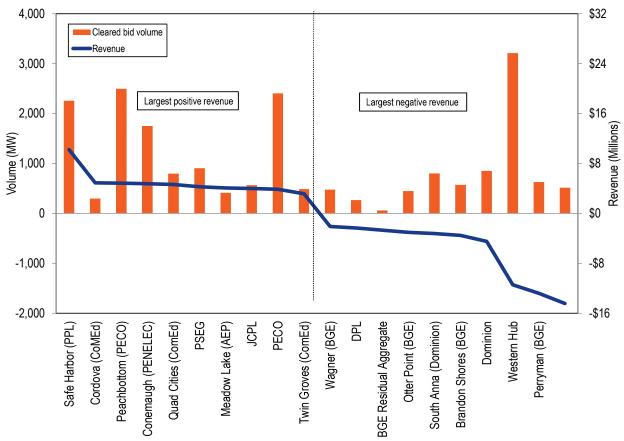


Figure H-3 summarizes the total revenue associated with all FTR sink points, regardless of source, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2017/2018 planning period. The top 10 positive revenue sinks accounted for $543.0 million (68.8 percent of total positive revenue from sinks) and 12.6 percent of all FTRs purchased. The top 10 negative revenue sinks accounted for -$26.9 million (23.7 percent of total negative revenue from sinks) and 4.9 percent of all FTRs purchased.

Figure H-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2017/2018

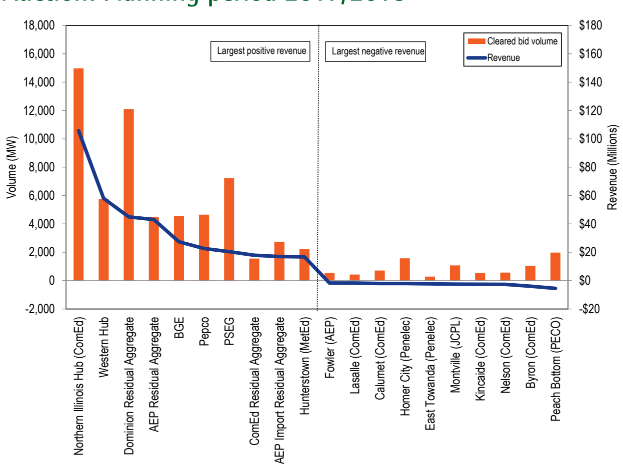


Figure H-4 summarizes total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Annual FTR Auction for the 2017/2018 planning period. The top 10 positive revenue sources accounted for $258.4 million (47.3 percent of total positive revenue from sources) and 9.8 percent of all FTRs purchased. The top 10 negative revenue sources accounted for -$22.5 million (21.2 percent of total negative revenue from sources) and 4.1 percent of all FTRs purchased.

Figure H-4 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2017/2018

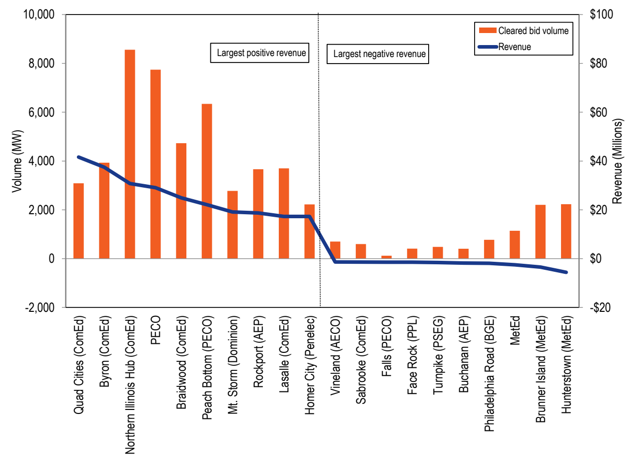


Figure H-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2017/2018 planning period. The top 10 positive revenue sinks accounted for $64.1 million (47.8 percent of total positive revenue from sinks) and 4.4 percent of all FTRs purchased. The top 10 negative revenue sinks accounted for -$20.5 million (19.0 percent of total negative revenue from sinks) and 0.7 percent of all FTRs purchased.

Figure H-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2017/2018 through December 31, 2017

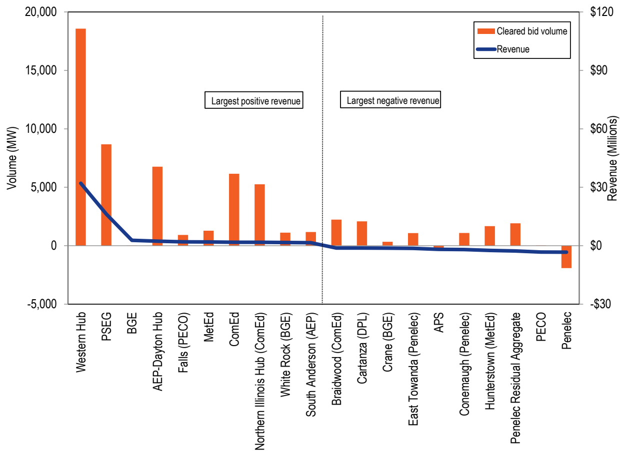
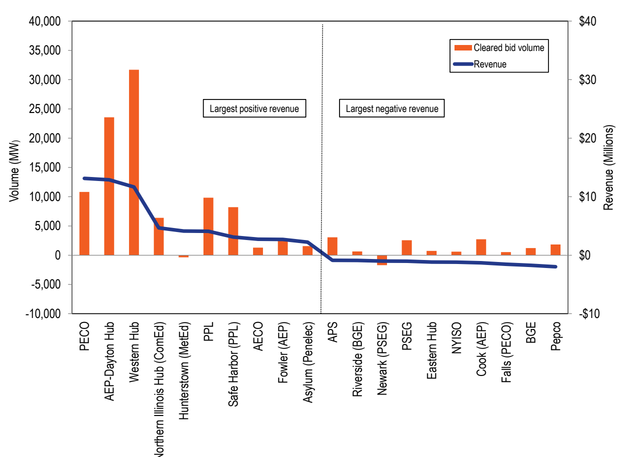


Figure H-6 summarizes the total revenue associated with all FTR source points, regardless of sink, that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2017/2018 planning period. The top 10 positive revenue sources accounted for $61.3 million (50.5 percent of total positive revenue from sources) and 8.3 percent of all FTRs purchased. The top 10 negative revenue sources accounted for -$12.7 million (13.3 percent of total negative revenue from sources) and 1.1 percent of all FTRs purchased.

Figure H-6 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2017/2018 through December 31, 2017



Appendix I Environmental and Renewable Energy Regulations

This appendix provides more detailed information about environmental and renewable energy regulations and the evolution of rules applicable within the PJM footprint.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

At the federal level, the Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Environmental Protection Agency (EPA) has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The Cross-State Air Pollution Rule (CSAPR) will require investments for some fossil fuel fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions.

State regulations and multi-state agreements have an impact on PJM markets. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from the Regional Greenhouse Gas Initiative (RGGI) affect some unit offers in the PJM energy market.

The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and when units do not clear, in the retirement of units. Federal and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have significant impacts on PJM wholesale markets.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[1] [2] The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[3] The rule established a compliance deadline of April 16, 2015.

In a related EPA rule also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA required new coal and oil fired electric utility generating units constructed after May 3, 2011, to

1 42 U.S.C. § 7401 et seq. (2000).

2 The EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

3 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).

comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM).[4]

The future of MATS is currently uncertain. On June 29, 2015, the U.S. Supreme Court remanded MATS to the U.S. Court of Appeals for the D.C. Circuit and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[5] The U.S. Supreme Court ruled in 2015 that "the EPA acted unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[6] The remand did not stay MATS and had no effect on the implementation of MATS. The EPA performed a cost review and made the required determination on cost in a supplemental finding.[7] On April 14, 2016, the EPA issued the required finding that "a consideration of cost does not cause us to change our determination that regulation of hazardous air pollutant (HAP) emissions from coal- and oil-fired EGUs is appropriate and necessary."[8] The rule has been effective since April 14, 2016, and remains effective. In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[9] On April 28, 2017, the Court granted EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[10]

Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[11] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and revised accordingly.

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) then in effect. On November 21, 2014, the EPA issued a rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015, and CSAPR's Phase 2 emissions effective January 1, 2017.[12] The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR.

In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[13] The CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. The CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[14] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[15]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[16] Group 2 does not include any states in the PJM region.[17] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[18]

4 NSPS are promulgated under CAA § 111.
5 Michigan et al. v. EPA, Slip Op. No. 14-46.
6 135 S. Ct. 2699, 2712 (2015).
7 *See Supplemental Finding That It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
8 *Supplemental Finding that it is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).
9 See Case No. 16-1127, et al.
10 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.
11 Nitric Oxides (NO_X), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).
12 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491.
13 CAA § 110(a)(2)(D)(i)(I).
14 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR"); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 34830 (June 12, 2012).
15 *Id.*
16 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.
17 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.
18 The EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM ($PM_{2.5}$) measures less than 2.5 microns across.

NAAQS and to reduce ozone season NO_x emissions to help downwind areas attain the 2008 8-Hour Ozone NAAQS.

CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty is assessed and allocated to resources within the state in proportion to their responsibility for the excess. The penalty requires surrender of two additional allowances for each allowance needed to the cover the excess.

On September 7, 2016, the EPA issued a final rule updating the CSAPR ozone season NO_x emissions program to reflect the decrease to the ozone season NAAQS that occurred in 2008 (CSAPR Update).[19] The CSAPR had been finalized in 2011 based on the 1997 ozone season NAAQS. The 2008 ozone season NO_x emissions level was lowered to 0.075 ppm from 0.08 in 1997.[20] The CSAPR Update increases the reductions required from upwind states to assist downwind states' ability to meet the lower 2008 standard.

The CSAPR Update also finalizes Federal Implementation Plans (FIPs) for each of the PJM states covered by CSAPR.[21] The EPA approves a FIP for states that fail to timely submit and obtain approval of their own implementation plan (SIPs).

Starting May 1, 2017, the CSAPR Update requires reduced summertime NO_x from power plants in certain PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.[22] The EPA has removed North Carolina from the ozone season NO_x trading program.[23] Table I-1 shows the revised reduced NO_x emissions budgets for each PJM affected state. Table I-1 also shows the assurance level, which is a hard cap on emissions, meaning that emissions above the assurance cannot be covered by emissions allowances, even if available.

Table I-1 Current and proposed CSAPR ozone season NO_x budgets for electric generating units (before accounting for variability)[24]

State	2017 CSAPR Ozone Season NO_x Budget for Electric Generating Units (before accounting for variability) (Tons)	Assurance Level (Tons)
Illinois	14,601	17,667
Indiana	23,303	28,197
Kentucky	21,115	25,549
Maryland	3,828	4,632
Michigan	17,023	20,598
New Jersey	2,062	19,094
Ohio	19,522	23,622
Pennsylvania	17,952	21,722
Tennessee	7,736	9,361
Virginia	9,223	11,160
West Virginia	17,815	21,556

During the delay of CSAPR implementation, the EPA estimates that there "will be approximately 350,000 banked allowances entering the CSAPR NO_x ozone season trading program by the start of the 2017 ozone season control period."[25] The EPA is concerned that "[w]ithout imposing a limit on the transitioned vintage 2015 and 2016 banked allowances, the number of banked allowances would increase the risk of emissions exceeding the CSAPR Update emission budgets or assurance levels and would be large enough to let all affected sources emit up to the CSAPR Update assurance levels for five consecutive ozone seasons."[26]

19 *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, EPA-HQ-OAR-2015-0500, 81 Fed. Reg. 74504 (–Oct. 26, 2016) ("CSAPR Update").

20 *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, NOPR, EPA-HQ-OAR-2009-0491, 75 Fed. Reg. 45210, 45220 (Aug. 2, 2010).

21 CSAPR Update at 74506 & n.9. PJM states that did not submit SIPs include Illinois, Maryland, Michigan, New Jersey, North Carolina, Pennsylvania, Tennessee, Virginia, and West Virginia; PJM states submitting SIPs but not obtaining approval include Indiana, Kentucky and Ohio. *Id.*

22 *Id.* at 74554.

23 *Id.* at 74507 n.13.

24 CSAPR Update at 74567.

25 *Id.* at 74588.

26 *Id.*

Accordingly, the EPA established a formulaic limit on the use of transitioned vintage 2015 and 2016 banked allowances.[27]

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[28] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules).[29]

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).[30]

On May 22, 2012, the EPA proposed amendments to the 2010 RICE NESHAP Rule.[31] The proposed rule would have allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The rule would have increased the 2010 Rule's 15 hour per year run limit. The exempted emergency demand response programs included RPM demand resources.

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[32] As a result, the national emissions standards uniformly apply to all RICE.[33] The Court held that the "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[34] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[35]

On April 15, 2016, the EPA issued a letter explaining how it would implement the vacatur order.[36] The EPA explained upon issuance of the Court's mandate, "an engine may not operate in circumstances described in the vacated [portions of the 2013 NESHAP RICE Rule] for any number of hours power per year."[37] The EPA explained that such engines could, however, continue to operate for specified emergency and nonemergency reasons.[38]

On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. Issuance of the mandate triggered implementation of the policy.

27 *Id.* at 74560. The EPA states: "The one-time conversion of the 2015 and 2016 banked allowances will be made using a calculated ratio, or equation, to be applied in early 2017 once compliance reconciliation (or 'true-up')s for the 2016 ozone season program is completed." *Id.*

28 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("2013 NESHAP RICE Rule"). In 2010, the EPA promulgated two rules with standards for hazardous air pollutant emissions from backup generators. The rules allowed backup generators to operate without emissions controls for fifteen hours each year as part of "demand response programs" during "emergency conditions that could lead to a potential electrical blackout." EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ ("2010 RICH NESHAP Rule").

29 *Id.*

30 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

31 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

32 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

33 *Id.*

34 DENREC v. EPA at 3, 20–21.

35 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.

36 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

37 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations).

38 See 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

The MMU is currently taking steps to ensure resource portfolios remain in compliance. The MMU contacted all CSPs with Demand Resources using diesel fuel to ensure compliance is met among all PJM resources.

Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[39 40]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[41] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer-reviewed.[42] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on social cost of carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[43 44] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[45] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[46]

The future of the Clean Power Plan is currently uncertain. On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based on its determination that the Plan exceeds the EPA's authority under Section 111 of the EPA Act.[47] On August 8, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order continuing for 60 days to hold in abeyance court proceedings challenging the Clean Power Plan.[48]

Federal Regulation of Environmental Impacts on Water

Water cooling systems at steam electric power generating stations are subject to regulation under the Clean Water Act (CWA).

The CWA applies to the waters of the United States (WOTUS). CWA defines WOTUS as "navigable waters."[49] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[50] The rule would avoid the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court.[51] The proposed rule would restore the pre 2015 rule to the code and the interpreting precedent applicable to the pre 2015 rule. As a result of the stay, the pre 2015 rule is now in effect. The pre 2015 rule includes all navigable

39 See CAA § 111.

40 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

41 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (August 8, 2016).

42 *Id.*

43 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

44 79 Fed. Reg. 1352 (January 8, 2014).

45 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule mimeo (August 3, 2015), also known as the "Clean Power Plan."

46 North Dakota v. EPA, et al., Order 15A793.

47 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (October 16, 2017).

48 See West Virginia v. EPA, No. 15-1363 (D.C. Cir.); North Dakota v. EPA, No. 15-1381 (D.C. Cir.).

49 33 U.S.C. § 1362(7).

50 80 Fed. Reg. 37054 (June 29, 2015).

51 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

waters and waters with a "significant nexus" to such waters.[52]

EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit.[53] Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from WOTUS and has a design intake flow of greater than two million gallons per day (mgd).[54]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[55]

Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal facilities are exposed under the act to civil suits, and criteria set by the EPA under subtitle D can be expected to influence the outcome of such litigation.

Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

The EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[56] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills

52 Rapanos v. U.S., 547 U.S. 715 (2006).

53 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve. EPA issued a rule providing an expansive definition of "waters of the United States" in 2015 that the current administration has indicated intent to review. See Executive Order: Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the "Waters of the United States" Rule (February 28, 2017) referring to "Clean Water Rule: Definition of 'Waters of the United States,'" 80 Fed. Reg. 37054 (June 29, 2015).

54 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

55 42 U.S.C. §§ 6901 *et seq.*

56 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

Table I-2 describes the criteria and anticipated implementation dates.

Table I-2 Minimum criteria for existing CCR ponds (surface impoundments) and landfills and date by which implementation is expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	October 17, 2018
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on such high energy demand days.[57] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[58] NO_x emissions limits for coal units became effective December 15, 2012.[59] NO_x emissions limits for other unit types became effective May 1, 2015.[60] As of December 31, 2017, two Cedar Station units, three Middle Street units, three Missouri units, one Sherman Ave unit, three Burlington units, three Edison units, four Essex units, three Kearny units, one Mercer unit, one National Park unit, one Sewaren unit, eight Glen Gardner units and four Werner units identified as NJ HEDD units have retired.[61] In total, 37 NJ HEDD units have retired and the remaining 41 NJ HEDD units are still operating after taking actions to comply with the HEDD regulations.

57 N.J.A.C. § 7:27–19.

58 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective noncatalytic reduction (SNCR).

59 N.J.A.C. § 7:27-19.4.

60 N.J.A.C. § 7:27-19.5.

61 See Current New Jersey Turbines that are HEDD Units, <http://www.nj.gov/dep/workgroups/docs/apcrule_20110909turbinelist.pdf>.

Table I-3 shows the HEDD emissions limits applicable to each unit type.

Table I-3 HEDD maximum NO_X emission rates[62]

Fuel and Unit Type	NO_x Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple Cycle Gas CT	1.00
Simple Cycle Oil CT	1.60
Combined Cycle Gas CT	0.75
Combined Cycle Oil CT	1.20
Regenerative Cycle Gas CT	0.75
Regenerative Cycle Oil CT	1.20

Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS).[63] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets.[64] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[65]

State Regulation of Greenhouse Gas Emissions

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[66] RGGI generates revenues for the participating states which have spent approximately 64 percent of revenues on energy efficiency, 16 percent on clean and renewable energy, 4 percent on greenhouse gas abatements and 10 percent on direct bill assistance.[67]

Table I-4 shows the RGGI CO_2 auction clearing prices and quantities for the 2009–2011 compliance period auctions, the 2012–2014 compliance period auctions and 2015–2017 compliance period auctions held as of December 31, 2017, in short tons and metric tonnes.[68] Prices for auctions held December 8, 2017, for the 2015–2017 compliance period were at \$3.80 per allowance (equal to one ton of CO_2), above the current price floor of \$2.05 for RGGI auctions.[69] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price decreased from the last auction clearing price of \$4.35 in September 2017.

62 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

63 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

64 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).

65 See *Id.*

66 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

67 *Investment of RGGI Proceeds Through 2015, The Regional Greenhouse Gas Initiative*, <https://www.rggi.org/docs/ProceedsReport/RGGI_Proceeds_Report_2015.pdf>.

68 The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of \$6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auctions to use CRRs.

69 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

Table I-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[70]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	31,513,765	31,513,765	$3.87	28,588,815	28,588,815
June 17, 2009	$3.23	30,887,620	30,887,620	$3.56	28,020,786	28,020,786
September 9, 2009	$2.19	28,408,945	28,408,945	$2.41	25,772,169	25,772,169
December 2, 2009	$2.05	28,591,698	28,591,698	$2.26	25,937,960	25,937,960
March 10, 2010	$2.07	40,612,408	40,612,408	$2.28	36,842,967	36,842,967
June 9, 2010	$1.88	40,685,585	40,685,585	$2.07	36,909,352	36,909,352
September 10, 2010	$1.86	45,595,968	34,407,000	$2.05	41,363,978	31,213,514
December 1, 2010	$1.86	43,173,648	24,755,000	$2.05	39,166,486	22,457,365
March 9, 2011	$1.89	41,995,813	41,995,813	$2.08	38,097,972	38,097,972
June 8, 2011	$1.89	42,034,184	12,537,000	$2.08	38,132,781	11,373,378
September 7, 2011	$1.89	42,189,685	7,847,000	$2.08	38,273,849	7,118,681
December 7, 2011	$1.89	42,983,482	27,293,000	$2.08	38,993,970	24,759,800
March 14, 2012	$1.93	34,843,858	21,559,000	$2.13	31,609,825	19,558,001
June 6, 2012	$1.93	36,426,008	20,941,000	$2.13	33,045,128	18,997,361
September 5, 2012	$1.93	37,949,558	24,589,000	$2.13	34,427,270	22,306,772
December 5, 2012	$1.93	37,563,083	19,774,000	$2.13	34,076,665	17,938,676
March 13, 2013	$2.80	37,835,405	37,835,405	$3.09	34,323,712	34,323,712
June 5, 2013	$3.21	38,782,076	38,782,076	$3.54	35,182,518	35,182,518
September 4, 2013	$2.67	38,409,043	38,409,043	$2.94	34,844,108	34,844,108
December 4, 2013	$3.00	38,329,378	38,329,378	$3.31	34,771,837	34,771,837
March 5, 2014	$4.00	23,491,350	23,491,350	$4.41	21,311,000	21,311,000
June 4, 2014	$5.02	18,062,384	18,062,384	$5.53	16,385,924	16,385,924
September 3, 2014	$4.88	17,998,687	17,998,687	$5.38	16,328,139	16,328,139
December 3, 2014	$5.21	18,198,685	18,198,685	$5.74	16,509,574	16,509,574
March 11, 2015	$5.41	15,272,670	15,272,670	$5.96	13,855,137	13,855,137
June 3, 2015	$5.50	15,507,571	15,507,571	$6.06	14,068,236	14,068,236
September 3, 2015	$6.02	25,374,294	25,374,294	$6.64	23,019,179	23,019,179
December 2, 2015	$7.50	15,374,274	15,374,274	$8.27	13,947,311	13,947,311
March 9, 2016	$5.25	14,838,732	14,838,732	$5.79	13,461,475	13,461,475
June 1, 2016	$4.53	15,089,652	15,089,652	$4.99	13,689,106	13,689,106
September 7, 2016	$4.54	14,911,315	14,911,315	$5.00	13,527,321	13,527,321
December 7, 2016	$3.55	14,791,315	14,791,315	$3.91	13,418,459	13,418,459
March 8, 2017	$3.00	14,371,300	14,371,300	$3.31	13,037,428	13,037,428
June 7, 2017	$2.53	14,597,470	14,597,470	$2.79	13,242,606	13,242,606
September 8, 2017	$4.35	14,371,585	14,371,585	$4.80	13,037,686	13,037,686
December 8, 2017	$3.80	14,687,989	14,687,989	$4.19	13,324,723	13,324,723

Zero Emissions Credits (ZEC) Programs

On December 7, 2016, the State of Illinois enacted legislation that, among other things, provides subsidies, known as zero emission credits (ZECs), for certain existing nuclear-powered generation units that indicated they would otherwise retire.[71] The ZEC program provides that starting June 1, 2017, the Illinois Power Agency (IPA) must procure ZECs under 10 year contracts with select Illinois nuclear power plants.[72]

The IPA must procure ZECs equal to 16 percent of 2014 Illinois retail load.[73] The initial base ZEC price equals $16.50/MWh and increases $1.00/MWh annually commencing with the 2023/2024 Delivery Year.[74] The base price is reduced by the amount that "the market price index for the applicable delivery year exceeds the baseline market price index for the consecutive 12-month period ending May 31, 2016."[75]

The revenues provided by the ZEC legislation are expected to forestall the retirement of a specific PJM nuclear unit in Illinois, the Quad Cities Generating Station.[76]

On February 14, 2017, the Electric Power Supply Association (EPSA) and others filed a complaint in the U.S. District Court for the Northern District of Illinois Eastern Division.[77] State defendants have filed a motion to dismiss and EPSA et al. have filed a motion for a stay. On April 24, 2017, the MMU filed an amicus curiae brief opposing the motion to dismiss and supporting the motion for a stay. The District Court granted the motion to dismiss on July 14, 2017. EPSA appealed to the U.S. Court of Appeals for the Seventh Circuit. On September 6, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

The ZEC legislation creates subsidies for existing units that create the same price suppressive effects as subsidies for new entry that are addressed by the Minimum Offer Price Rule.[78] The MMU has supported

70 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 23, 2018).

71 See Illinois 99th Gen. Assemb., S.B. 2814 (Dec. 7, 2016), which can be accessed at: <http://www.ilga.gov/legislation/99/SB/09900SB2814lv.htm>. The Governor of Illinois signed the ZEC legislation, amending the Illinois Power Agency Act ("IPAA"), on December 7, 2016; see also ICC, et al., Potential Nuclear Power Plant Closings in Illinois (Jan. 5, 2015), which can be accessed at: <http://www.ilga.gov/reports/special/report_potential%20nuclear%20power%20plant%20closings%20in%20il.pdf>.

72 See IPAA § 1-75(d-5)(1).

73 See *id.*

74 See IPAA § 1-75(d-5)(1)(B).

75 See *id.*

76 See Ted Caddell, RTO Insider "Exelon's Crane Reports 'Monumental Year,'" (Feb. 8, 2017); Exelon, Press Release, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants" (June 2, 2016) (citing "lack of progress on Illinois energy legislation" as a key factor), <http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement>; Thomas Overton, Power, "Byron, Three Mile Island Nuclear Plants at Risk, Exelon Says" (June 7, 2016) (reporting Exelon statement that Byron is "economically challenged"), <http://www.powermag.com/byron-three-mile-island-nuclear-plants-at-risk-exelon-says/?printmode=1>.

77 Case No. 17-cv-01164.

78 OATT Attachment DD § 5.14(h).

modification of the Minimum Offer Price (MOPR) Rules to apply to existing units receiving subsidies.[79] The MMU's proposed modification of the MOPR rules would, if in place, apply to nuclear units receiving subsidies. Such subsidies may otherwise result in noncompetitive offers in PJM markets that would be addressed on a unit specific basis.

A similar issue has arisen in New York, where the New York Public Service Commission (New York PSC) established a program requiring the purchase of ZEC credits from specific nuclear facilities in upstate New York. The constitutionality of the New York PSC's program has been challenged in a case pending before the U.S. District Court for the Southern District of New York.[80] On January 9, 2017, the MMU filed an amicus curiae brief supporting plaintiffs on the grounds that the ZEC subsidies interfere with the operation of wholesale power markets in New York and have price suppressive effects in the energy markets in PJM.[81] In a decision issued July 25, 2017, the District Court dismissed the case. The Coalition for Competitive Electricity appealed to the U.S. Court of Appeals for the Second Circuit. On October 23, 2017, the MMU filed a brief of amicus curiae supporting the appeal. The appeal is pending.

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS by generating power from eligible technologies or purchasing RECs are penalized with alternative compliance payments. As of September 30, 2017, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of September 30, 2017, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[82]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[83]

79 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EL16-49-000 (April 11, 2016).

80 Coalition for Competitive Electricity, et al., v. Audrey Zibelman, et al., Case No. 1:16-cv-08164-VEC (USDC SDNY).

81 Brief of Amicus Curiae of Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM, USDC SDNY Case No. 1:16-cv-08164-VEC (Jan. 9, 2017).

82 See the Indiana Utility Regulatory Commission's "2017 Annual Report," at 37 (Oct. 2017) <http://www.in.gov/iurc/files/IURC%20annual%20report%20web.pdf>.

83 See Enr. Com. Sub. For H. B. No. 2001.

Appendix J Glossary

Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Area Control Error (ACE)

Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.

Associated unit (AU)

A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.

Auction Revenue Right (ARR)

A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.

Automatic Generation Control (AGC)

An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.

Average hourly LMP

An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.

Avoidable cost rate (ACR)

The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.

Avoidable Project Investment Recovery Rate (APIR)

A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market

Energy that is generated and financially settled during real time.

Base Residual Auction (BRA)

Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Behind the Meter

Behind The Meter Generation refers to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market. (OATT 1.3B)

Bilateral agreement

An agreement between two parties for the sale and delivery of a service.

Black Start Unit

A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.

Block Loaded
A resource offered to PJM in the energy or capacity market at a single MW output which is not dispatchable in the energy market and cannot be partially cleared in the capacity market.

Bottled generation
Economic generation that cannot be dispatched because of local operating constraints.

Burner tip fuel price
The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.

Bus
An interconnection point.

Capacity deficiency rate (CDR)
The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.

Capacity Emergency Transfer Limit (CETL)
The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity queue
A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)
An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion Turbine (CT)
A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)
A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

Control Zone
An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.

Decrement Bids (DEC)
An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).

Demand deviations
Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.

Demand Resource
A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Dispatch Rate
The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.

Disturbance Control Standard
A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)

Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.

Eastern Region

Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.

Economic generation

Units producing energy at an offer price less than or equal to LMP.

Effective MW

The MW of regulation provided by a regulating resource multiplied by that resource's marginal benefit factor and performance score.

End use customer

Any customer purchasing electricity at retail.

Equivalent availability factor (EAF)

The proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORd)

A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.

Equivalent forced outage factor (EFOF)

The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)

The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)

The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource

A generation resource located outside metered boundaries of the PJM RTO.

Financial Transmission Right (FTR)

A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.

Firm Point-to-Point Transmission Service

Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.

Firm Transmission Service

Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid

Bid to purchase a defined MW level of energy, regardless of LMP.

Fixed Resource Requirement (FRR)

An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flowgate

A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.

Frequently mitigated unit (FMU)

A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Fuel Diversity Index

Objective metric of fuel diversity, defined by $\mathrm{FDI} = 1 - \sum_{i=1}^{N} s_i^2$, where *si* is the share of fuel type *i*. The FDI is calculated separately for energy output and for installed capacity.

Generation Control Area (GCA) and Load Control Area (LCA)
Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms "Control Area" in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.

Generator deviations
Hourly deviations in the generator category, equal to the difference between a unit's cleared day-ahead generation, and a unit's hourly, integrated real-time generation.

Generation Offers
Schedules of MW offered and the corresponding offer price.

Generation owner
A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross export volume (energy)
The sum of all export transaction volume (MWh).

Gross import volume (energy)
The sum of all import transaction volume (MWh).

Gigawatt (GW)
A unit of power equal to 1,000 megawatts.

Gigawatt-day
One GW of energy flow or capacity for one day.

Gigawatt-hour (GWh)
One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)
HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.

Hertz (Hz)
Electricity system frequency is measured in hertz.

Hot/Cold Weather Alerts
A Hot Weather Alert is issued to prepare personnel and facilities for extreme hot and/or humid weather conditions that may cause unit unavailability to be higher than forecast for an extended period. It can be issued on a control zone basis and PJM communicates to members whether fuel limited resources are to be placed into Maximum Emergency category.

A Cold Weather Alert is issued to prepare personnel and facilities for extreme cold weather conditions. It can be initiated when actual temperatures in a zone fall near or below ten degrees Fahrenheit or at higher temperatures if PJM projects a portion of gas fired capacity is unable to obtain spot market gas during load pick-up periods.

HRSG
Heat recovery steam generator. An air-to-steam heat exchanger.

Increment offers (INC)
Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Incremental Auction
Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

Inframarginal unit
A unit that is operating, with an accepted offer that is less than the clearing price.

Installed capacity
Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.

Load
Demand for electricity at a given time.

Load Management
Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

Load-serving entity (LSE)
Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.

Locational Deliverability Area (LDA)
Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal Benefit Factor
For RegD resources, this is the marginal rate of substitution between RegA and RegD resources.

Marginal unit
The last, highest cost, generation unit to supply power under a merit order dispatch system.

Market-clearing price
The price that is paid by all load and paid to all suppliers.

Market participant
A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.

Market user interface
A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.

Maximum daily starts
The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.

Maximum weekly starts
The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.

Mean
The arithmetic average.

Median
The midpoint of data values. Half the values are above and half below the median.

Megawatt (MW)
A unit of power equal to 1,000 kilowatts.

Megawatt-day
One MW of energy flow or capacity for one day.

Megawatt-hour (MWh)
One MWh is a megawatt produced or consumed for one hour.

Megawatt-year
One MW of energy flow or capacity for one calendar year.

Minimum down time
The minimum amount of time that a unit has to stay off before starting again. An operating parameter incorporated in a unit's schedule.

Minimum Offer Price Rule (MOPR)
The MOPR rule sets a floor offer price in the RPM Capacity Market, based on the average net cost of new entry (CONE) for certain classes of new or uprated generation capacity resources as defined in the OATT Attachment DD 5.13(h).

Minimum run time
The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.

Monthly CCM
The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).

Multimonthly CCM
The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)
The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.

Net exchange (capacity)
Capacity imports less exports.

Net interchange (energy)
Gross import volume less gross export volume in MWh.

Network Transmission Service
Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.

Noneconomic generation
Units producing energy at an offer price greater than the LMP.

Non-Firm Transmission Service
Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

Nonsynchronized Reserve
Reserve MW available within ten minutes, but not synchronized to the grid.

North American Electric Reliability Council (NERC)
A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Off peak
For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.

On peak
For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.

Opportunity cost
In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule
A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.

Performance Score
This is a measure of the quality of response of a regulating resource to its assigned regulation signal (RegA or RegD).

PJM member
Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.

PJM planning year
The calendar period from June 1 through May 31.

Point of Receipt (POR) and Point of Delivery (POD)
Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.

Pool-scheduled resource
A generating resource that the seller has turned over to PJM for scheduling and control.

Price duration curve

A graphic representation of the percent of hours that a system's price was at or below a given level during the year.

Price-sensitive bid

Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.

Primary operating interfaces

Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.

Qualified Replacement Resource

Generation resource used to replace retired resources that were historical Stage 1A source points for FTRs.

Ramp-limited desired (MW)

The achievable MW based on the UDS requested ramp rate.

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

RegA

PJM's slow-oscillation regulation signal designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. PJM can satisfy the RTO-wide regulation requirement with only RegA resources.

RegD

PJM's fast-oscillation regulation signal designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. PJM cannot satisfy the RTO-wide regulation requirement with only RegD resources.

Regional Transmission Expansion Planning (RTEP) Protocol

The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria. Regulation

Regulation is an ancillary service that corrects short-term imbalances between generation and load and is provided by resources capable of responding to a PJM-generated signal.

Reliability*First* Corporation

Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).

Reliability Pricing Model (RPM)

PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Reserve

Energy available within a defined time for the purpose of correcting an imbalance between supply and demand.

Seasonal Conditional Demand

An adjustment to the DASR requirement for summer and winter seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year.

Selective catalytic reduction (SCR)

NO_x reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation

Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.

Shadow price

The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.

Sources and sinks

Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service

Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.

Spot market

Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.

Static Var compensator

A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.

Summer Net Capability

The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

Summer conditions shall reflect the 50 percent probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday.

For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations

Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.

Synchronized reserve

Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.

System installed capacity

System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.

System lambda

The cost to the PJM system of generating the next unit of output.

Temperature-humidity index (THI)

A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = T_d – (0.55 – 0.55RH) * (T_d – 58) if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)

Transmission Adequacy and Reliability Assessment (TARA)

An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.

Transmission Constraint Penalty Factor

In the PJM energy market optimization, the power flow on a transmission constraint is allowed to exceed its limit under some conditions. The violations incur a cost called a transmission penalty factor expressed in $/MWh. Following the principles of optimization, the shadow price or the marginal value of the transmission constraint can never exceed the transmission constraint penalty factor. For this reason, the transmission constraint penalty factor is also called marginal value limit.

Turn down ratio

The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through

An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.

Winter Weather Parameter (WWP)

WWP is wind speed adjusted temperature. WWP is defined as: WWP = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)

Zone

See "Control zone" (above).

Appendix K List of Acronyms

AC2	Advanced Control Center
ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AFD	Adjusted Fixed Demand
AGC	Automatic generation control
ALM	Active load management
ALR	Automatic load rejection black start
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMI	Advanced Metering Infrastructure
AMIL	Ameren - Illinois
AMRN	Ameren
APS	Allegheny Power System
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ASO	Ancillary Service Optimization
ATC	Available transfer capability
ATSI	American Transmission Systems, Inc.
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BACT	Best Available Control Technology
BCPEP	BGE Pepco Interface
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
BOR	Balancing Operating Reserve
BORCA	Balancing operating reserve cost allocation
BRA	Base Residual Auction
BSSWG	Black Start Services Working Group
BTU	British thermal unit
BTM	Behind the meter
C&I	Commercial and industrial customers
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CCR	Cost Containment Reserves
CDR	Capacity deficiency rate
CDS	Cost Development Subcommittee
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIDS	Critical Infrastructure Protocol
CIN	Cinergy Corporation
CIR	Capacity injection rights
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPI	Consumer Price Index

CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment service provider
CSTF	Capacity Senior Task Force
CT	Combustion turbine
CTO	Combustion Turbine Optimizer
CTR	Capacity transfer right
DAOR	Day – Ahead Operating Reserve
DASR	Day-Ahead Scheduling Reserve
DARRCA	Day – ahead reliability and reactive cost allocation
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DGP	Degree of Generator Performance
DL	Diesel
DLC	Direct Load Control
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DRS	Demand Response Subcommittee
DRSDTF	Demand Response Subzonal Dispatch Task Force
DSIRE	Database of State Incentives for Renewables & Efficiency
DSR	Demand side response
DUK	Duke Energy Corporation
EAC	Excess Availability Capacity
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy efficiency
EEA	Emergency energy alert
EERS	Energy Efficiency Standards
EES	Enhanced energy scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EGU	Electric Generating Units
EHV	Extra-high-voltage
EIS	Environmental Information Services
EKPC	East Kentucky Power Cooperative, Inc.
ELRP	Economic load response program
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EMUSTF	Energy Market Uplift Senior Task Force
EPA	Environmental Protection Agency
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
ESP	Electrostatic precipitators (Baghouses)
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FDIc	Fuel Diversity Index for capacity
FDIe	Fuel Diversity Index for energy generation
FFE	Firm flow entitlement
FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement

FSL	Firm service load
FTR	Financial transmission right
GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GLD	Guaranteed load drop
GSU	Generator Step-Up Transformers
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous air pollutants
HE	Hour Ending
HEDD	NJ High Energy Demand Day
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IARR	Incremental ARRs
IA	RPM Incremental Auction
IBTs	Internal Bilateral Transactions
ICAP	Installed capacity
ICCP	Inter-control center protocol
ICSA	Interconnection construction service agreement
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
IGCC	Integrated Gasification Combined Cycle
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IPSTF	Interconnection Process Senior Task Force
IRM	Installed reserve margin
IROL	Interconnection Reliability Operating Limit
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
ITSCED	Intermediate term security constrained economic dispatch
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
KV	KiloVolt
KDAEV	Known Day-Ahead Error Value
LAER	Lowest Achievable Emissions Rate
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LGIA	Large generator interconnection agreement
LGIP	Large generator interconnection procedure
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LMTF	Load Management Task Force
LOC	Lost opportunity cost
LPC	Locational Pricing Calculator
LSE	Load-serving entity
M2M	Market to market
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MACT	Maximum Achievable Control Technology

MAD	Mid-Atlantic Dominion subzone
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards rule
MBF	Marginal Benefit Factor
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midcontinent Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MOPR	Minimum Offer Price Rule
MOPR-Ex	Minimum Offer Price Rule Extended
MP	Market participant
MP2	Monitored Priority 2
MRC	Markets and reliability committee
MRT	Minimum run time
MTSL	Minimum Tank Suction Level
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NAAQS	National Ambient Air Quality Standards
NBT	Net Benefits Test
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC Line
NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NNL	Network and native load
NOPR	Notice of Proposed Rulemaking
NO_x	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NSRMCP	Nonsynchronized Reserve Market Clearing Price
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPSI	Organization of PJM States, Inc.
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee

PAR	Phase angle regulator
PATH	Potomac – Appalachian Transmission Highline
PCLLRW	Post Contingency Local Load Relief Warning
PE	PECO Zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator

PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak Load Contribution
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPB	Parts per billion
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSD	Prevention of Significant Deterioration
PSN	PSEG north
PSNC	PSEG north central
QF	Qualifying Facility
QRR	Qualified Replacement Resource
RAA	Reliability Assurance Agreement among Load-Serving Entities
RAC	Reliability Assessment Commitment
RCF	Reciprocal Coordinated Flowgate
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCCP	Regulation market capability clearing price
RMCP	Regulation market-clearing price
RMPCP	Regulation market performance clearing price
RMR	Reliability Must Run
ROFR	Right of First Refusal
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RRMSE	Relative Root Mean Squared Error
RSI	Residual supply index
RSIx	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTSCED	Real time security constrained economic dispatch
RTO	Regional transmission organization
SAA	Symmetrical Additive Adjustment
SCE&G	South Carolina Energy and Gas
SCD	Seasonal Conditional Demand
SCED	Security Constrained Economic Dispatch
SCPA	South central Pennsylvania subarea

SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	SERC Reliability Corporation
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SIPs	State Implementation Plan
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNCR	Selective Non-Catalytic Reduction
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
SRSTF	System Restoration Strategy Task Force
STD	Standard deviation
STRPTAS	Short Term Resource Procurement Applicable Share
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TrAIL	Trans – Allegheny Interstate Line
TSA	Thunderstorm Alert
TSIN	NERC Transmission System Information Network
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UCSA	Upgrade construction service agreement
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
ULSD	Ultra-Low Sulfur Diesel
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOCs	Volatile Organic Compounds
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages
ZEC	Zero Emissions Credit